

Exhibit A-1

Proposed Reliability Standard CIP-002-6
Clean

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:
All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

- 4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
 - 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
 - 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
 - 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.
5. **Effective Date:** See Implementation Plan for CIP-002-6.
6. **Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples include, to the extent they are within the ESP: file servers, FTP servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber System according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber System according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Associated Documents

- See Implementation Plan for CIP-002-6.
- See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more

implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions

- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)

- Know generation status, capability, ramp rate, start time (GO, BA)
- Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)

- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and

operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities,” there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as, “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may

be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units

designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical

borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in Attachment 1 of NERC's "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)" document, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted

that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“Laar”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

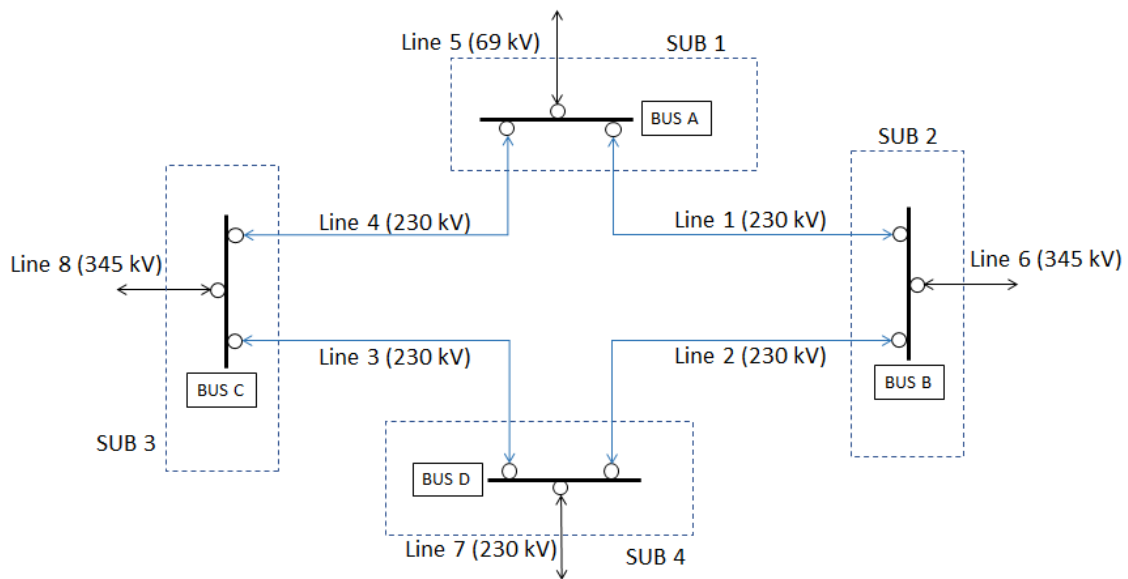
In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).

- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

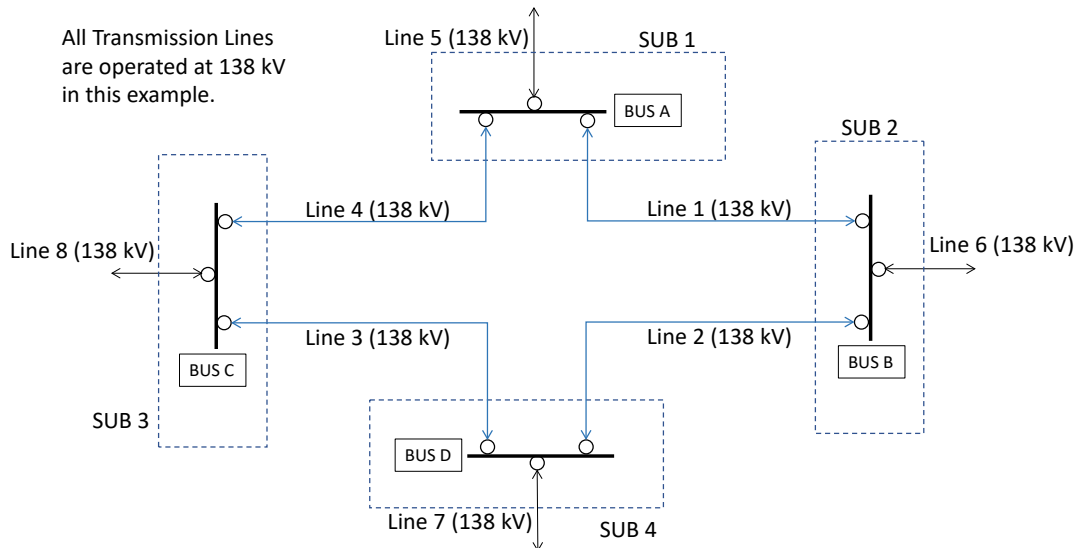
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection

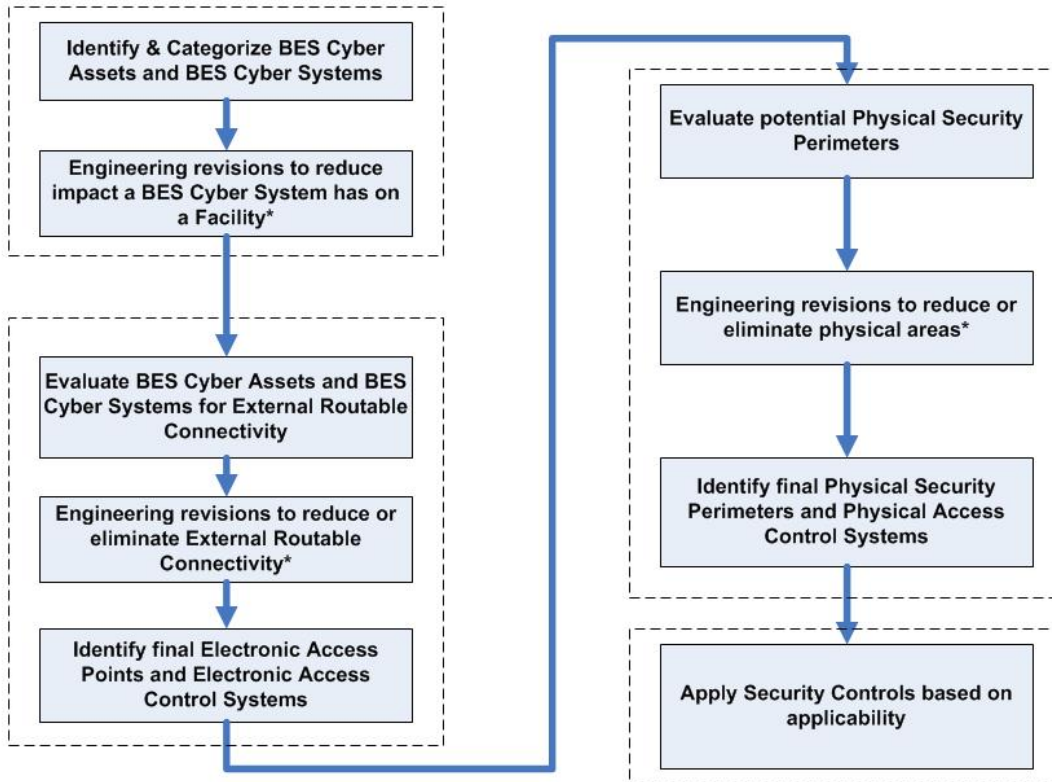
point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Exhibit A-2

Proposed Reliability Standard CIP-002-6
Redline

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-~~5.1a6~~
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** -For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” -For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~**4.1.6.4.1.5. Reliability Coordinator**~~

~~**4.1.7.4.1.6. Transmission Operator**~~

~~**4.1.8.4.1.7. Transmission Owner**~~

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-~~5.1a6~~:

- 4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
- 4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-002-6.

~~24 Months Minimum — CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

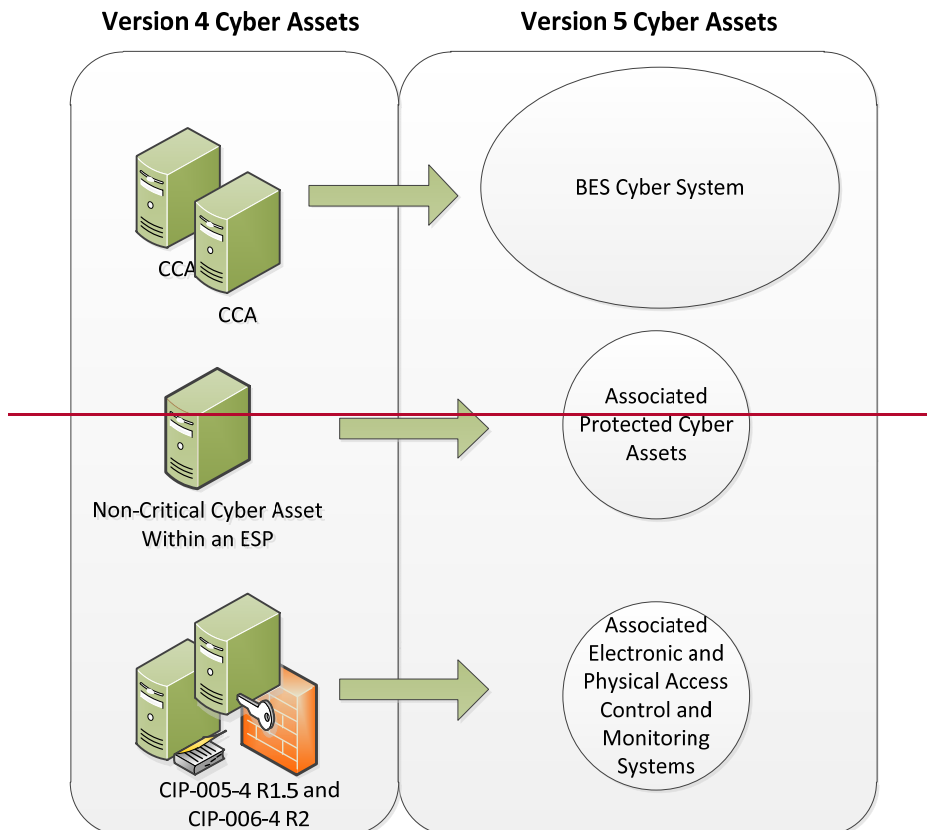
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4).~~ The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-

developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the characteristics in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these ~~Version 5~~ CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement **R1** only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria,

~~Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11~~Section 1 or Section 2, and listed in Section 3 default to ~~be~~ low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the ~~Version 5~~ CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples ~~may~~ include, to the extent they are within the ESP: file servers, ~~ftp~~ FTP servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** ~~The Each~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

- 1.1. Compliance Enforcement Authority:** “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

- 1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

- 1.3. Compliance Monitoring and ~~Assessment-Enforcement Program~~Processes:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot-Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~

• ~~Complaint~~

1.4 Additional Compliance Information:

None.

Violation Severity Levels 2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Associated Documents

- See Implementation Plan for CIP-002-6.
- See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

Version History

~~CIP-002-5.1a~~

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.

Version	Date	Action	Change Tracking
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
<u>6</u>	<u>5/14/2020</u>	<u>Adopted by the NERC Board of Trustees.</u>	<u>Modified Criterion 2.12.</u>

~~CIP-002-51.a Attachment 1~~

~~Impact Rating Criteria~~

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating ~~(H)~~

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a

reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.
~~Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating ~~(L)~~

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-~~5.1a6~~ and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-~~5.1a6~~. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-~~5.1a6~~

CIP-002-~~5.1a6~~ requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. -The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-~~5.1a-6~~. The concept includes a number of named BES reliability operating services.

- These named services include: Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities₂”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as₂ “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along

with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-~~5.1a6~~, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating ~~(H)~~

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, ~~BA~~s, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of

BA footprints shows that the majority of BasBAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is “to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.” In particular, it requires that “as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency.” The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a “long term” reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is

necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.

- Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in [Attachment 1 of NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index" document, Attachment 1](#), the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those **Special Protection Systems (SPS)**, Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a, that monitor and control BES Transmission Operator Lines with an aggregate weighted value of 6000 or higher, and that have not already been categorized as high impact included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient

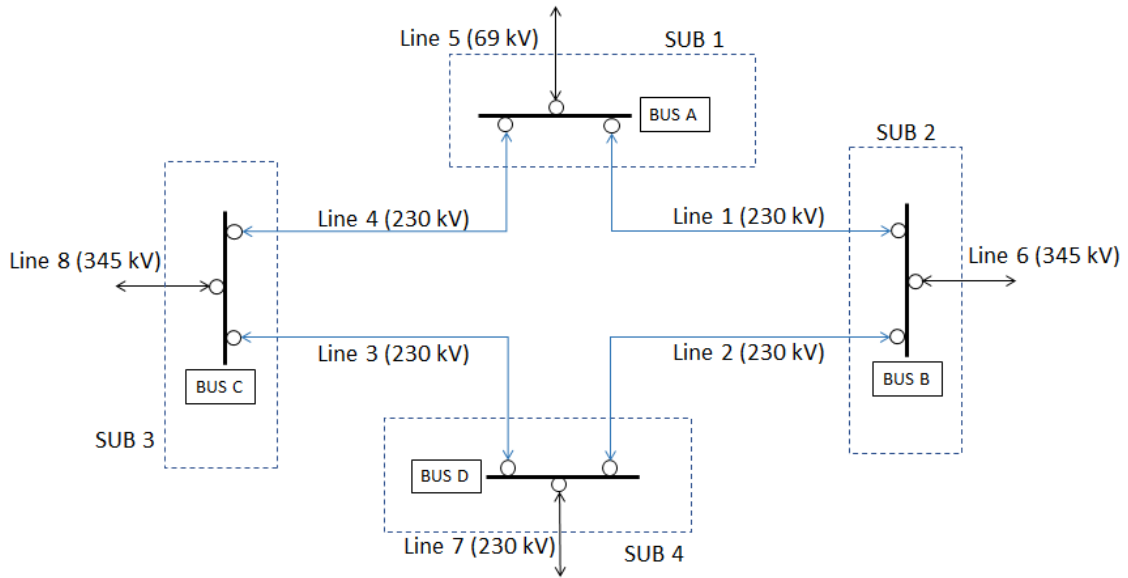
differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

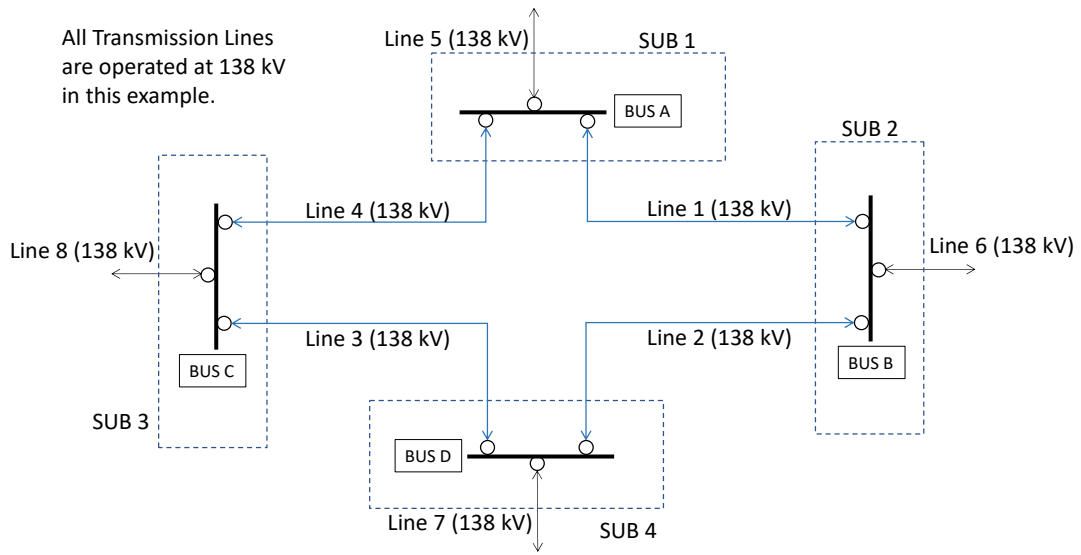
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>Line 5</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>None</u>	<u>0</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 7</u>	<u>3500</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>Line 6, Line 8</u>	<u>2600</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$700+700+700+700+700+1300+1300 = 6100$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>None</u>	<u>N/A</u>

<u>100 kV to 199 kV</u>	<u>250</u>	<u>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</u>	<u>2000</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>None</u>	<u>0</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>None</u>	<u>0</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not

relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

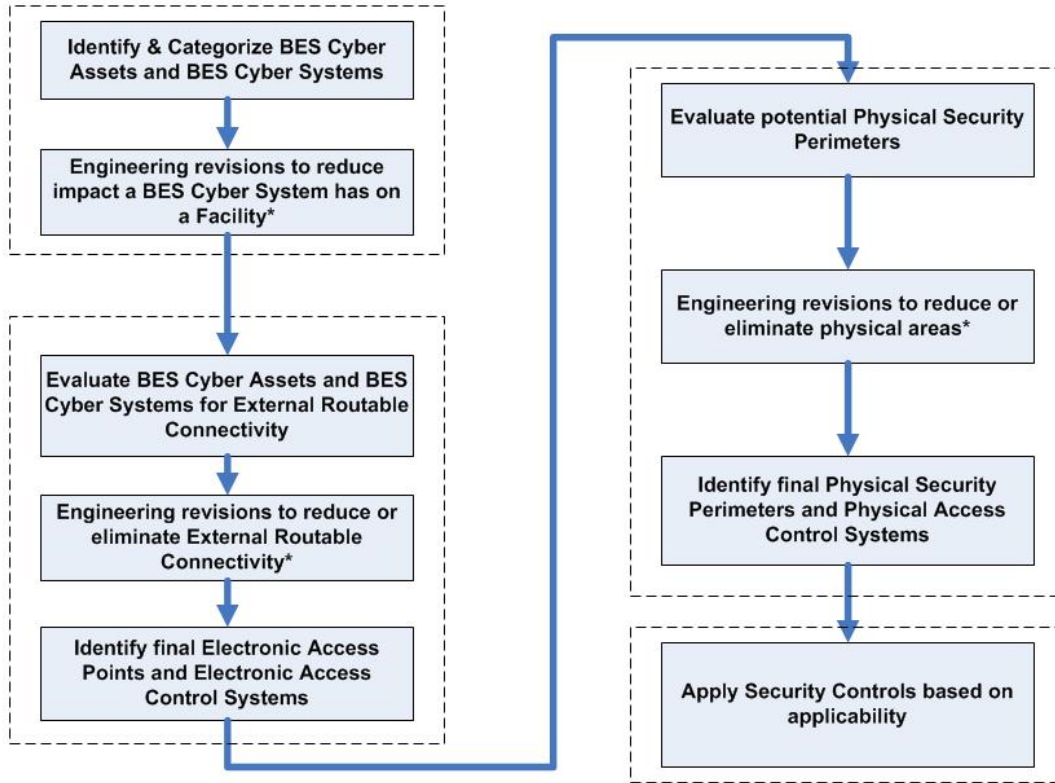
Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example

of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
 - 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
 - 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Exhibit B

Implementation Plan

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security - BES Cyber System Categorization

Prerequisite Standard(s) or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

This Implementation Plan includes phased-in implementation dates for Criterion 2.12 of CIP-002-6, Attachment 1. The phased-in implementation dates allow Responsible Entities¹ a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion of it),

¹ As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter immediately after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 of Attachment 1 to CIP-002-6 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For *planned* changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* of the CIP-002-5.1a Implementation Plan.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *unplanned* changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* of the CIP-002-5.1a Implementation Plan.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Exhibit D

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

Justification for VRFs and VSLs

- Requirement R1: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.
- Requirement R2: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.

Exhibit E

Summary of Development History and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard CIP-002-6.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give “due weight” to the technical expertise of the ERO.¹ The technical expertise of the ERO is derived from the standard drafting team (“SDT”) selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.² For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2016-02 Modifications to CIP Standards SDT members is included in **Exhibit G**.

II. Standard Development History

A. Standard Authorization Request Development

On March 9, 2016, the Standards Committee authorized posting a Standards Authorization Request (“SAR”) to address Commission directives from Order No. 822³ and issues identified by the CIP Version 5 Transition Advisory Group for a 30-day informal comment period from March 23, 2016 through April 4, 2016 and authorized the solicitation of nominations for the Project 2016-02 Modifications to CIP Standards SDT.⁴ Based on comments received, the SDT revised the SAR

¹ Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2018).

² The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

³ *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037, at P 17, *order on reh’g*, 156 FERC ¶ 61,052 (2016).

⁴ NERC, *Meeting Minutes – Standards Committee Meeting* (Mar. 9, 2016), <https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20March%209,%202016.pdf>.

and posted for another 30-day informal comment period from June 1, 2016 through June 30, 2016. The Standards Committee accepted the revised SAR on July 20, 2016.⁵

B. First Posting - Comment Period, Initial Ballot, and Non-binding Poll

On September 7, 2017, the Standards Committee authorized initial posting of proposed Reliability Standard CIP-002-6, the associated Implementation Plan, Violation Risk Factors (“VRFs”), Violation Severity Levels (“VSLs”), and other associated documents for a 45-day formal comment period from September 14, 2017 through October 30, 2017, with a parallel initial ballot and non-binding poll held during the last 10 days of the comment period from October 20, 2017 through October 30, 2017.⁶ The initial ballot for proposed CIP-002-6 received 66.78 percent approval, reaching quorum at 86.21 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 65.08 percent supportive opinions, reaching quorum at 84.27 percent of the ballot pool. There were 76 sets of responses, including comments from approximately 192 different individuals and approximately 129 companies, representing all 10 industry segments.⁷

C. Second Posting - Comment Period, Additional Ballot, and Non-binding Poll

Proposed Reliability Standard CIP-002-6 and the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 45-day formal comment period from March 16, 2018 through April 30, 2018, with a parallel additional ballot and non-binding poll held

⁵ NERC, *Meeting Minutes – Standards Committee Meeting* (July 20, 2016), <https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20July%2020,%202016.pdf>.

⁶ NERC, *Minutes – Standards Committee Meeting* (Sept. 7, 2017), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved_September_7_2017.pdf.

⁷ NERC, *Consideration of Comments – CIP-002-6, Project 2016-02 Modifications to CIP Standards* (Mar. 16, 2018), https://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/CIP-002-6_Response_to_Comments_03162018.pdf.

during the last 10 days of the comment period from April 20, 2018 through April 30, 2018. The additional ballot for proposed CIP-002-6 received 93.31 percent approval, reaching quorum at 81.01 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 93.22 percent supportive opinions, reaching quorum at 79.15 percent of the ballot pool. There were 52 sets of responses, including comments from approximately 150 different individuals and approximately 105 companies, representing all 10 industry segments.⁸

D. Supplemental Standard Authorization Request Development

On June 13, 2018, the Standards Committee accepted a SAR to address recommendations for revisions to proposed CIP-002-6 from the Project 2015-09 Establish and Communicate System Operating Limits SDT; authorized posting the SAR for a 30-day informal comment period from June 14, 2018 through July 13, 2018; and authorized the Project 2016-02 Modifications to CIP Standards SDT to revise the CIP Reliability Standards according to the SAR.⁹

E. Third Posting - Comment Period, Initial Ballot, and Non-binding Poll

On August 22, 2018, the Standards Committee authorized initial posting of proposed Reliability Standard CIP-002-6, the associated Implementation Plan, VRFs, VSLs, and other associated documents for a 45-day formal comment period from August 23, 2018 through October 9, 2018, with a parallel initial ballot and non-binding poll held during the last 10 days of the comment period from September 28, 2018 through October 9, 2018.¹⁰ The initial ballot for proposed CIP-002-6 received 55.89 percent approval, reaching quorum at 79.08 percent of the

⁸ Because the 2nd posting was followed by a comment period and initial ballot, the SDT did not respond to comments received during the 2nd posting.

⁹ NERC, *Minutes – Standards Committee Meeting* (June 13, 2018), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes_Aproved_July_18_2018.pdf.

¹⁰ NERC, *Minutes – Standards Committee Meeting* (Aug. 22, 2018), <https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20September%202013,%202018.pdf>.

ballot pool. The non-binding poll for the associated VRFs and VSLs received 51.55 percent supportive opinions, reaching quorum at 78.76 percent of the ballot pool. There were 61 sets of responses, including comments from approximately 150 different individuals and approximately 101 companies, representing all 10 industry segments.¹¹

F. Fourth Posting - Comment Period, Additional Ballot, and Non-binding Poll

Proposed Reliability Standard CIP-002-6 and the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 45-day formal comment period from June 3, 2019 through July 17, 2019, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from July 8, 2019 through July 17, 2019. The additional ballot for proposed CIP-002-6 received 87.39 percent approval, reaching quorum at 86.11 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 86.16 percent supportive opinions, reaching quorum at 84.38 percent of the ballot pool. There were 69 sets of responses, including comments from approximately 148 different individuals and approximately 107 companies, representing 10 industry segments.¹²

G. Fifth Posting - Comment Period, Additional Ballot, and Non-binding Poll

Proposed Reliability Standard CIP-002-6 and the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 45-day formal comment period from November 1, 2019 through December 16, 2019, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from December 6, 2019 through December

¹¹ Pursuant to SPM Section 4.12, the SDT did not need to respond to comments received during the 3rd posting because significant revisions were made to the subsequent draft of the standard for the 4th posting. NERC notified stakeholders of the significant revisions via email announcement sent on May 29, 2019 prior to conducting the 4th posting on June 3, 2019.

¹² NERC, *Consideration of Comments – CIP-002-6*, Project 2016-02 Modifications to CIP Standards, available at https://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/2016-02_CIP-002-6_Consideration_of_Comments_June_2019_Posting_03262020.pdf.

16, 2019. The additional ballot for proposed CIP-002-6 received 95.98 percent approval, reaching quorum at 81.89 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 97.74 percent supportive opinions, reaching quorum at 80.72 percent of the ballot pool. There were 52 sets of responses, including comments from approximately 119 different individuals and approximately 93 companies, representing all 10 industry segments.¹³

H. Final Ballot

Proposed Reliability Standard CIP-002-6 was posted for a 10-day final ballot period from March 26, 2020 through April 6, 2020. The ballot for proposed Reliability Standard CIP-002-6 and associated documents reached quorum at 87.92 percent of the ballot pool, receiving affirmative support from 96.28 percent of the voters.

I. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standard CIP-002-6 on May 14, 2020.¹⁴

¹³ NERC, *Consideration of Comments – CIP-002-6*, Project 2016-02 Modifications to CIP Standards, available at https://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/2016-02_CIP-002-6_Consideration_of_Comments_Nov_2019_Posting_03262020.pdf.

¹⁴ NERC, *Board of Trustees Agenda Package*, Agenda Item 5.a. (Project 2016-02 Modifications to CIP Standards (CIP-002-6)) available at https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Agenda_Package_May_14_2020_PUBLIC-POSTING.pdf.

Complete Record of Development

[Home](#) > [Program Areas & Departments](#) > [Standards](#) > [Project 2016-02 Modifications to CIP Standards](#)

Project 2016-02 Modifications to CIP Standards

[Related Files](#)

Status

The 10-day final ballot for CIP-002-6 - Cyber Security – BES Cyber System Categorization concluded 8 p.m. Eastern, Monday, April 6, 2020. The voting results are posted below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

The Version 5 Transition Advisory Group (V5 TAG) transferred issues to the Version 5 SDT that were identified during the industry transition to implementation of the Version 5 CIP Standards. Specifically, the issues that the SDT will address are:

- Cyber Asset and BES Cyber Asset Definition
- Network and Externally Accessible Devices
- Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations
- Virtualization

On January 21, 2016, FERC issued [Order No. 822](#) Revised Critical Infrastructure Protection Reliability Standards. In this order, FERC approved revisions to version 5 of the CIP standards and also directed that NERC address each of the Order 822 directives by developing modifications to requirements in CIP standards and the definition of Low Impact External Routable Connectivity (LERC), or the SDT shall develop an equally efficient and effective alternative. To address concerns identified in Order 822, the Commission directed the following:

- Develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability.
- Develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).
- Develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule, to the LERC definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

Standard(s) Affected – CIP-002-5.1, CIP-003-6, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, CIP-012-1

Purpose/Industry Need

The SDT will modify the CIP family of standards (or develop an equally efficient and effective alternative) to:

- Address issues identified by the CIP V5 TAG;
- Address FERC directives contained in Order 822; and
- Address requests for interpretations as directed by the NERC Standards

[Subscribe to this project's observer mailing list](#)

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2016-02 Modifications to CIP Standards Observer List" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft				
CIP-002-6	Final Ballot			
Clean (93) Redline to Last Approved (94)	Info (97)	03/26/20 - 04/06/20	Ballot Results (98)	
Implementation Plan	Vote			
Clean (95) Redline to Last Posted (96)				
Draft 4				
CIP-002-6	Additional Ballot and Non-binding Poll		Ballot Results (91)	
Clean (81) Redline to Last Posted (82)	Updated Info (89)	12/06/19 – 12/16/19	Non-binding Poll Results (92)	
Implementation Plan (83)	Info (90)			
	Vote			
Supporting Materials				
Unofficial Comment Form (Word) (84)				
VRF/VSL Justification (85)	Comment Period			Consideration of Comments (88)
	Info (86)	11/01/19 – 12/16/19	Comments Received (87)	
	Submit Comments			
CIP-005				
Clean Redline	Comment Period			
Associated Definitions	Info	08/09/19 – 09/26/19	Comments Received	
Supporting Materials	Submit Comments			

<p>Unofficial Comment Form (Word) Technical Rationale</p>				
<p>Draft 3 CIP-002-6 Clean (67) Redline to Last Approved (CIP-002-51.a) (68) Implementation Plan* (69) Supporting Materials Unofficial Comment Form (Word) (70) VRF/VSL Justification* (71)</p>	<p>Additional Ballot and Non-binding Poll Updated Info (77) Info (78) Vote</p>	<p>07/08/19 - 07/17/19</p>	<p>Ballot Results (79) Non-binding Poll Results (80)</p>	
<p>*Due to the amount of redlines that would be reflected from the last approved, these documents are only being posted as clean versions Draft Reliability Standard Audit Worksheet (RSAW) Clean (72) Redline (73)</p>	<p>Comment Period Info (74) Submit Comments</p>	<p>06/03/19 - 07/17/19</p>	<p>Comments Received (75)</p>	<p>Consideration of Comments (76)</p>
	<p>Join Ballot Pools</p>	<p>06/03/19 - 07/02/19</p>		
<p>Virtualization and Future Technologies: Case for Change White Paper Supporting Materials Unofficial Comment Form (Word) Virtualization Case for Change Webinar Q & A</p>	<p>Comment Period Info Submit Comments</p>	<p>05/30/19 - 06/28/19</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>
<p>Final Draft CIP-003-8 Clean Redline to Last Posted Redline to Last Approved (Updated) Implementation Plan Clean Redline to Last Posted Supporting Materials VRF/VSL Justification Clean Redline to Last Posted Reliability Standard Audit Worksheet Clean Redline</p>	<p>Final Ballot Info Vote</p>	<p>04/18/19 - 04/29/19</p>	<p>Ballot Results</p>	
<p>Standard Drafting Team Nominations Supporting Materials Unofficial Nomination Form (Word) (65)</p>	<p>Nomination Period Info (66) Submit Nominations</p>	<p>02/28/19 - 03/29/19</p>		
<p>CIP Virtualization Updates CIP-004-7 Clean Redline CIP-005-7 Clean Redline CIP-006-7 (Updated documents posted 11/14/18) Clean Redline CIP-007-7 Clean Redline</p>	<p>Comment Period Info</p>	<p>11/02/18 - 12/18/18</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>

<p>CIP-010-4 Clean Redline</p> <p>Definitions (Redline)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form</p> <p>Technical Rationales</p> <p>CIP-005-7</p> <p>CIP-007-7</p> <p>CIP-010-4</p>	<p>Submit Comments</p>			
<p>Draft 1</p> <p>CIP-002-6 Clean (53) Redline to Last Posted (54)</p> <p>Implementation Plan Clean (55) Redline to Last Posted (56)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word) (57)</p> <p>VRF/VSL Justification Clean (58) Redline to Last Posted</p>	<p>Initial Ballot and Non-binding Poll</p> <p>Updated Info (61)</p> <p>Info (62)</p> <p>Vote</p> <p>Comment Period</p> <p>Info (59)</p> <p>Submit Comments</p> <p>Join Ballot Pools</p> <p>Initial Ballot and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p> <p>Comment Period</p> <p>Info</p> <p>Submit Comments</p> <p>Join Ballot Pools</p>	<p>09/28/18 - 10/09/18</p> <p>08/23/18 - 10/09/18</p> <p>08/23/18 - 09/21/18</p> <p>09/28/18 - 10/09/18</p> <p>08/23/18 - 10/09/18</p> <p>08/23/18 - 09/21/18</p>	<p>Ballot Results (63)</p> <p>Non-binding Poll Results (64)</p> <p>Comments Received (60)</p> <p>Ballot Results</p> <p>Non-binding Poll Results</p> <p>Comments Received</p> <p>Consideration of Comments</p>	
<p>Final Draft</p> <p>CIP-012-1 Clean Redline to Last Posted</p> <p>Implementation Plan</p> <p>Supporting Materials</p> <p>VRF/VSL Justification Clean Redline to Last Posted</p> <p>Technical Rationale Clean Redline to Last Posted</p> <p>Implementation Guidance Clean Redline to Last Posted</p> <p>Draft Reliability Standard Audit Worksheet (RSAW) Clean Redline</p>	<p>Final Ballot</p> <p>Info</p> <p>Vote</p>	<p>08/03/18 - 08/13/18</p>	<p>Ballot Results</p>	

<p>Standards Authorization Requests</p> <p>FERC Order No. 843 (Malicious Code Example)</p> <p>IROL Modifications to CIP-002 (49)</p> <p>Supporting Materials</p> <p>Unofficial Comment Forms (Word)</p> <p>FERC Order No. 843</p> <p>IROL Modifications to CIP-002 (50)</p>	<p>Comment Periods</p> <p>Info (51)</p> <p>Submit Comments</p>	<p>06/14/18 - 07/13/18</p>	<p>Comments Received</p> <p>FERC Order No. 843 (Malicious Code)</p> <p>IROL Modifications to CIP-002 (52)</p>	
<p>Draft 4</p> <p>CIP-012-1</p> <p>Clean Redline to Last Posted</p> <p>Implementation Plan</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word)</p> <p>VRF/VSL Justification</p> <p>Clean Redline to Last Posted</p> <p>Technical Rationale</p> <p>Clean Redline to Last Posted</p> <p>Implementation Guidance</p> <p>Clean Redline to Last Posted</p> <p>Draft Reliability Standard Audit Worksheet (RSAW)</p> <p>Clean Redline to Draft 3</p>	<p>Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>05/18/18 - 07/03/18</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>
	<p>Additional Ballot and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>Additional Ballot</p> <p>06/22/18 - 07/03/18</p> <p>Non-binding Poll</p> <p>6/22/18 - 7/5/18</p> <p>Extended to reach quorum</p>	<p>Ballot Results</p> <p>Non-binding Poll Results</p>	
	<p>Info</p> <p>Send RSAW feedback to: RSAWfeedback@nerc.net</p>			
<p>Standard Drafting Team Nominations</p> <p>Supporting Materials</p> <p>Unofficial Nomination Form (Word)</p>	<p>Nomination Period</p> <p>Info</p> <p>Submit Nominations</p>	<p>04/24/18 - 05/23/18</p>		
<p>Proposed Definition of Control Center</p> <p>Implementation Plan</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word)</p>	<p>Initial Ballots for the Definition and Implementation Plan</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>04/20/18 - 04/30/18</p>	<p>Definition Ballot Results</p> <p>Implementation Plan Ballot Results</p>	<p>Consideration of Comments</p>
	<p>Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>03/16/18 - 04/30/18</p>	<p>Comments Received</p>	
	<p>Join Ballot Pools</p>	<p>03/16/18 - 04/16/18</p>		
<p>Draft 2</p> <p>CIP-002-6</p> <p>Clean (34) Redline to Last Approved (35)</p>	<p>Additional Ballot and Non-binding Poll</p>	<p>04/20/18 - 04/30/18</p>	<p>Ballot Results (46)</p>	

<p>Implementation Plan Clean (36) Redline to Last Approved (37)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word) (38)</p> <p>VRF/VSL Justification Clean (39) Redline to Last Posted (40)</p> <p>Consideration of Issues and Directives Clean (41) Redline to Last Posted (42)</p>	<p>Updated Info (43)</p> <p>Info (44)</p> <p>Vote</p>		<p>Non-binding Poll Results (47)</p>	
<p>Draft Reliability Standard Audit Worksheet (RSAW) Clean Redline to CIP-002-5.1a CIP-012-1 Clean Redline to Last Posted</p> <p>Implementation Plan</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word)</p> <p>Consideration of Issues and Directives Clean Redline to Last Posted</p> <p>VRF/VSL Justification Clean Redline to Last Posted</p> <p>Implementation Guidance Clean Redline to Last Posted</p> <p>Technical Rationale Clean Redline to Last Posted</p>	<p>Additional Ballot and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>03/16/18 - 04/30/18</p>	<p>Comments Received (48)</p>	
<p>Technical Rationale Clean Redline to Last Posted</p> <p>Technical Rationale and Justification for CIP-012-1</p> <p>Draft Reliability Standard Audit Worksheet (RSAW) Implementation Guidance for CIP-012-1 Clean Redline to Draft 2</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word)</p>	<p>Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>04/20/18 - 04/30/18</p>	<p>Ballot Results</p> <p>Non-binding Poll Results</p>	<p>Consideration of Comments</p>
<p>Draft 2 CIP-012-1 Clean Redline to Last Posted</p> <p>Implementation Plan Clean Redline to Last Posted</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word)</p> <p>Consideration of Issues and Directives Clean Redline to Last Posted</p> <p>VRF/VSL Justification Clean Redline to Last Posted</p> <p>Draft Reliability Standard Audit Worksheet (RSAW) Clean Redline to Last Posted</p>	<p>Additional Ballot and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>11/20/17 - 12/11/17</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>
<p>Virtualization/Unofficial Comment Form (Word)</p>	<p>Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>12/01/17 - 12/11/17 (The Non-binding Poll was extended to 12/12/17 to reach quorum)</p>	<p>Ballot Results</p> <p>Non-Binding Poll Results</p>	<p>Consideration of Comments</p>
			<p>Comments Received</p>	

<p>Draft 1</p> <p>CIP-002-6 Clean (20) Redline to Last Approved (21)</p> <p>Implementation Plan (22) Supporting Materials</p> <p>Unofficial Comment Form (Word) (23)</p> <p>VRF/VSL Justification (24)</p> <p>Consideration of Issues and Directives (25)</p> <p>Draft Reliability Standard Audit Worksheet (RSAW) Clean (18) Redline to CIP-002-5.1a (19) Proposed Definition of Control Center</p>	<p>Initial Ballot and Non-binding Poll Updated Info (26) Info (27) Vote</p>	<p>10/20/17 - 10/30/17</p>	<p>Ballot Results (30) Non-binding Poll Results (31)</p>	
<p>Technical Rationale and Justification for CIP-012-1</p> <p>Supporting Materials</p> <p>Unofficial Comment Form - Proposed Definition of Control Center</p> <p>Unofficial Comment Form - Technical Rationale and Justification for CIP-012-1</p>	<p>Comment Period Info (28) Submit Comments</p> <p>Join Ballot Pools</p> <p>Info (29)</p> <p>Send RSAW feedback to: RSAWfeedback@nerc.net</p>	<p>09/14/17 - 10/30/17</p> <p>09/14/17 - 10/13/17</p> <p>10/04/17 - 10/30/17</p>	<p>Comments Received (32)</p> <p>Consideration of Comments (33)</p>	
<p>Draft 1</p> <p>CIP-012-1</p> <p>Implementation Plan Supporting Materials</p> <p>Unofficial Comment Form (Word)</p> <p>Consideration of Issues and Directives</p> <p>VRF/VSL Justification</p> <p>Draft Reliability Standard Audit Worksheet (RSAW)</p>	<p>Initial Ballot and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p> <p>Comment Period</p> <p>Info</p> <p>Submit Comments</p> <p>Join Ballot Pools</p> <p>Info</p> <p>Send RSAW feedback to: RSAWfeedback@nerc.net</p>	<p>09/01/17 - 09/11/17</p> <p>07/27/17 - 09/11/17</p> <p>07/27/17 - 08/25/17</p> <p>08/17/17 - 09/11/17</p>	<p>Ballot Results</p> <p>Non-binding Poll Results</p> <p>Comments Received</p> <p>Consideration of Comments</p>	
<p>TOCC White Paper (14)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word) (15)</p>	<p>Comment Period Info (16) Submit Comments</p>	<p>03/14/17 - 04/11/17</p>	<p>Comments Received (17)</p>	
	<p>Comment Period</p>			

Virtualization/Unofficial Comment Form	Info Submit Comments	03/14/17 - 04/11/17	Comments Received	
Comment Period				
Communication Networks/Unofficial Comment Form	Info Submit Comments	02/10/17 - 03/13/17	Comments Received	
Comment Period				
CIP Exceptional Circumstances/Unofficial Comment Form	Info Submit Comments	02/10/17 - 03/13/17	Comments Received	
Final Draft				
CIP-003-7(i) Clean Redline to Last Posted	Final Ballots Info Vote	01/30/17 - 02/08/17	Ballot Results CIP-003-7(i) Implementation Plan	
Implementation Plan Clean Redline to Last Posted			TCA Definition	
Definition of Terms Used in Standards (TCA and Removable Media) Clean Redline to Last Posted			Removable Media Definition	
Draft 1				
CIP-003-7(i) Clean Redline to Last Approved Redline to CIP-003-7	Initial Ballots and Non-binding Poll Updated Info Info Vote	01/16/17 - 01/25/17 (The Non-binding Poll was extended to 01/26/17 to reach quorum)	Ballot Results CIP-003-7(i) Implementation Plan TCA Definition	
Implementation Plan			Removable Media Definition	
Definition of Terms Used in Standards (TCA and Removable Media)			Non-binding Poll	
Supporting Documents				
Unofficial Comment Form (Word)				
VRF/VSL Justification	Comment Period Info Submit Comments	12/12/16 - 01/25/17	Comments Received	Consideration of Comments
Consideration of Issues and Directives				
Join Ballot Pools				
CIP-003-7(i) Draft Reliability Standard Audit Worksheet (RSAW) Updated Clean Redline to CIP-003-6	Updated Info Send RSAW feedback to: RSAWfeedback@nerc.net	12/12/16 - 01/10/17 The existing CIP-003-7 (LERC) ballot pool was used for all of the ballots associated with this portion of the project. The ballot pools have been re-opened to allow stakeholders to join if they are not existing members.	12/27/16 - 01/25/17 Updated RSAW posted January 20, 2017	

<p>Final Draft</p> <p>CIP-003-7 Clean Redline to Last Posted Implementation Plan Clean Redline to Last Posted</p>	<p>Final Ballots Info Vote</p>	<p>12/09/16 - 12/19/16</p>	<p>Ballot Results</p> <p>CIP-003-7 Implementation Plan</p>	
<p>CIP-003-TCA Clean Redline to CIP-003-6</p> <p>TCA Implementation Plan</p> <p>Supporting Documents</p> <p>Unofficial Comment Form (Word)</p> <p>TCA Consideration of Issues and Directives</p> <p>TCA VRF and VSL Justification</p> <p>TCA Definition</p>	<p>Informal Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>11/01/16 - 11/18/16</p>	<p>Comments Received</p>	
<p>Draft 2</p> <p>CIP-003-7 Clean Redline to Last Posted Redline to Last Approved</p> <p>Implementation Plan Clean Redline to Last Posted</p> <p>Supporting Documents</p> <p>Unofficial Comment Form (Word)</p> <p>VRF and VSL Justification Clean Redline to Last Posted</p> <p>Consideration of Issues and Directives Clean Redline to Last Posted</p> <p>CIP-003-7 Draft Reliability Standard Audit Worksheet (RSAW) Clean Redline</p>	<p>Additional Ballots and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>11/23/16 - 12/05/16</p>	<p>Ballot Results</p> <p>CIP-003-7 Implementation Plan Non-binding Poll</p>	
	<p>Comment Period</p> <p>Info</p> <p>Submit Comments</p>	<p>10/21/16 - 12/05/16</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>
	<p>Info</p> <p>Send RSAW feedback to: RSAWfeedback@nerc.net</p>	<p>11/04/16 - 12/05/16</p>		
<p>Draft 1</p> <p>CIP-003-7 Clean Redline to Last Approved</p> <p>Definition of Term(s) Used in Standards Clean Redline</p> <p>Implementation Plan</p> <p>Supporting Documents</p> <p>Unofficial Comment Form (Word)</p> <p>VRF and VSL Justification</p> <p>Consideration of Issues and Directives</p>	<p>Initial Ballots and Non-binding Poll</p> <p>Updated Info</p> <p>Info</p> <p>Vote</p>	<p>08/26/16 - 09/06/16</p>	<p>Ballot Results</p> <p>CIP-003-7 Implementation Plan LERC and its Definition Non-binding Poll</p>	
	<p>Comment Period</p> <p>Info</p> <p>Vote</p>	<p>07/21/16 - 09/06/16</p>	<p>Comments Received</p>	<p>Consideration of Comments</p>
	<p>Join Ballot Pools</p>	<p>07/21/16 - 08/19/16</p>		

<p>Draft CIP-003-7 Reliability Standard Audit Worksheet (RSAW) Clean Redline</p>	<p>Info Send RSAW Feedback to: RSAWfeedback@nerc.net</p>	<p>08/10/16 - 09/06/16</p>		
<p>The Standards Committee accepted the Standards Authorization Request on July 20, 2016</p>				
<p>Standards Authorization Request Clean (8) Redline to Last Posted (9)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (10)</p> <p>CIP Version 5 Transition Advisory Group Issues for Consideration (11)</p>	<p>Comment Period Info (12) Submit Comments</p>	<p>06/01/16 - 06/30/16</p>	<p>Comments Received (13)</p>	
<p>Standards Authorization Request (3)</p> <p>Supporting Materials</p> <p>Unofficial Comment Form (Word) (4)</p> <p>CIP Version 5 Transition Advisory Group Issues for Consideration (5)</p>	<p>Comment Period Info (6) Submit Comments</p>	<p>03/23/16 - 04/21/16</p>	<p>Comments Received (7)</p>	
<p>Supplemental Standard Drafting Team Nominations</p> <p>Supporting Materials</p> <p>Unofficial Nomination Form (Word) (1)</p>	<p>Nomination Period Info (2) Submit Nominations</p>	<p>03/10/16 - 03/23/16</p>		

Unofficial Nomination Form

Project 2016-02 Modifications to CIP Standards

Supplemental Nomination Period

Nominations for additional standard drafting team (SDT) members are being solicited for **Project 2016-02 Modifications to CIP Standards**. Use the [electronic form](#) to submit nominations by **8 p.m. Eastern, Wednesday, March 23, 2016**. This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Documents and information about this project are available on the [Project 2016-02 Modifications to CIP Standards](#) page. If you have questions, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Background

This solicitation for nominations is to supplement the existing Project 2016-02 Modifications to CIP Standards SDT that is continuing to address the work in the Project 2016-02 Modifications to CIP Standards Authorization Request (SAR). NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas:

- Operations technology
- Communication networks
- Virtualization
- Protection of transient electronic devices
- Network and externally accessible devices
- Cyber Asset and BES Cyber Asset definitions
- Transmission Owner (TO) Control Centers
- Critical Infrastructure Protection (“CIP”) family of Reliability Standards

The time commitment for Project 2016-02 is expected to be significant. Participants should anticipate an average workload of 20 hours per week devoted to the drafting team efforts. In-person meetings will occur typically for 2 ½ - 3 days most months (not including travel time) and meetings will take place in different parts of North America. When not meeting in person, regularly scheduled

conference calls will be used to conduct drafting team work. Outside the scheduled meetings, individuals or subgroups will have additional preparation and support work such as researching and developing proposed concepts, reviewing proposals, compiling comments and drafting responses, etc. Lastly, outreach is an important component of this drafting team’s effort. Members of the team are expected to interact with other stakeholders during the revision development process.

Name:		
Organization:		
Address:		
Telephone:		
E-mail:		
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):		
<p>If you are currently a member of any NERC drafting team, please list each team here:</p> <p><input type="checkbox"/> Not currently on any active SAR or standard drafting team.</p> <p><input type="checkbox"/> Currently a member of the following SAR or standard drafting team(s):</p>		
<p>If you previously worked on any NERC drafting team please identify the team(s):</p> <p><input type="checkbox"/> No prior NERC SAR or standard drafting team.</p> <p><input type="checkbox"/> Prior experience on the following team(s):</p>		
Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
<input type="checkbox"/> FRCC <input type="checkbox"/> MRO <input type="checkbox"/> NPCC	<input type="checkbox"/> RF <input type="checkbox"/> SERC <input type="checkbox"/> SPP RE	<input type="checkbox"/> Texas RE <input type="checkbox"/> WECC <input type="checkbox"/> NA – Not Applicable
Select each Industry Segment that you represent:		
<input type="checkbox"/>	1 — Transmission Owners	

<input type="checkbox"/>	2 — RTOs, ISOs
<input type="checkbox"/>	3 — Load-serving Entities
<input type="checkbox"/>	4 — Transmission-dependent Utilities
<input type="checkbox"/>	5 — Electric Generators
<input type="checkbox"/>	6 — Electricity Brokers, Aggregators, and Marketers
<input type="checkbox"/>	7 — Large Electricity End Users
<input type="checkbox"/>	8 — Small Electricity End Users
<input type="checkbox"/>	9 — Federal, State, and Provincial Regulatory or other Government Entities
<input type="checkbox"/>	10 — Regional Reliability Organizations and Regional Entities
<input type="checkbox"/>	NA – Not Applicable

Select each Function¹ in which you have current or prior expertise:

<input type="checkbox"/> Balancing Authority	<input type="checkbox"/> Transmission Operator
<input type="checkbox"/> Compliance Enforcement Authority	<input type="checkbox"/> Transmission Owner
<input type="checkbox"/> Distribution Provider	<input type="checkbox"/> Transmission Planner
<input type="checkbox"/> Generator Operator	<input type="checkbox"/> Transmission Service Provider
<input type="checkbox"/> Generator Owner	<input type="checkbox"/> Purchasing-selling Entity
<input type="checkbox"/> Interchange Authority	<input type="checkbox"/> Reliability Coordinator
<input type="checkbox"/> Load-serving Entity	<input type="checkbox"/> Reliability Assurer
<input type="checkbox"/> Market Operator	<input type="checkbox"/> Resource Planner
<input type="checkbox"/> Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

¹ These functions are defined in the NERC [Functional Model](#), which is available on the NERC web site.

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.

Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Supplemental Nomination Period Open through **March 23, 2016**

[Now Available](#)

Nominations are being sought for additional standard drafting team (SDT) members through **8 p.m. Eastern, Wednesday, March 23, 2016**.

Use the [electronic form](#) to submit a nomination. If you experience any difficulties in using the electronic form, contact [Wendy Muller](#). An unofficial Word version of the nomination form is posted on the [Standard Drafting Team Vacancies](#) page and the [project page](#).

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required.

The time commitment for this project is expected to be significant. Participants should anticipate an average workload of 20 hours per week devoted to the SDT efforts. In person meetings will occur typically for 2 ½ - 3 days most months (not including travel time) and meetings will take place in different parts of North America. When not meeting in person, regularly scheduled conference calls will be used to conduct drafting team work. Outside the scheduled meetings, individuals or subgroups will have additional preparation and support work such as researching and developing proposed concepts, reviewing proposals, compiling comments and drafting responses, etc. Lastly, outreach is an important component of this SDT's effort. Members of the team are expected to interact with other stakeholders during the revision development process.

See the [project page](#) and unofficial nomination form for more information.

Next Steps

The Standards Committee is expected to appoint members to the team in April 2016. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326

404-446-2560 | www.nerc.com

Standards Authorization Request Form

When completed, email this form to:

sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard(s):	Modifications to CIP Standards		
Date Submitted:	March 9, 2016		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC		
Telephone:	609-651-9455	E-mail:	Stephen.Crutchfield@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):

The purpose of this project is to (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the *CIP V5 Issues for Standard Drafting Team Consideration* (V5TAG Transfer Document) and (2) address the Federal Energy Regulatory Commission (Commission) directives contained in Order 822. These revisions will increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities.

Industry Need (What is the industry problem this request is trying to solve?):

The V5TAG, which consists of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP version 5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing standard drafting team (SDT) for the CIP Reliability Standards.

SAR Information

The V5 TAG developed the V5TAG Transfer Document to explain the issues and recommend that the SDT consider them in future development activity.

On January 21, 2016, the Commission issued Order No. 822 approving revisions to the CIP version 5 standards and also directing NERC to develop modifications to address:

- Protection of transient electronic devices used at low-impact BES Cyber Systems;
- Protections for communication network components between control centers; and
- Refinement of the Low Impact External Routable Connectivity (LERC) definition.

The Commission did not provide a date by which the modifications for transient devices or communication networks must be completed. For the LERC definition, however, the Commission directed that NERC submit the modification within one year of the effective date of Order No. 822 (March 31, 2017).

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The proposed project will consider the issues raised by the V5TAG in the V5TAG Transfer Document and will address the Commission directives in Order No. 822 through modifications to the CIP standards. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards and will meet the deadlines established by the Commission in Order No. 822.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

As stated above, the purpose of this project is to consider the V5TAG issues in the initial transfer document V5TAG Transfer Document and address the Commission directives contained in Order 822. For the directive on the LERC definition, the project is to respond within the deadline required in the order.

As noted above, the V5TAG identified specific issues with the CIP V5 standards. The V5TAG drafted the V5TAG Transfer Document to formally recommend that the SDT address these issues during standards development to consider whether modifications can be made to the standard language. As outlined in the V5TAG Transfer Document, the specific issues are as follows:

- Cyber Asset and BES Cyber Asset (BCA) Definitions – as foundational definitions within the CIP V5 standards, the understanding of Cyber Asset and BCA terms impacts the scope of the applicable requirements. The V5TAG recommends the following enhancements:
 - Clarify the intent of “programmable” in Cyber Asset.
 - Clarify and focus the definition of “BES Cyber Asset” including:

SAR Information

- Focusing the definition so that it does not subsume all other cyber asset types.
 - Considering a lower bound to the term ‘adverse’ in “adverse impact”.
 - Clarifying the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
- Network and Externally Accessible Devices – V5TAG recommends improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
 - The 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters”
 - The meaning of the word ‘associated’ in the ERC definition.
 - The applicability of ERC including the concept of the term “directly” used in the phrase “cannot be directly accessed through External Routable Connectivity” within the Applicability section.
 - The IRA definition placement of the phrase “using a routable protocol” in the definition and with respect to Dial-up Connectivity.
 - The Guidelines and Technical Basis sentence, “If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.”
- Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations – V5TAG is aware of multiple interpretations of the language “used to perform the functional obligation of” in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
 - The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
 - The definition of Control Center.
 - The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.
- Virtualization – The CIP V5 standards do not specifically address virtualization. Because of the increasing use of virtualization in industrial control system environments, V5TAG asked that the SDT consider CIP-005 and the definitions of Cyber Asset and Electronic Access Point regarding permitted architecture and the security risks of network, server and storage virtualization technologies.

The SDT shall also address the Order No. 822 directives by developing modifications to requirements in CIP standards and the definition of LERC. The Commission directed the following:

- *Per paragraph 32, “...we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission’s concerns, the proposed modifications should be designed to effectively address the risks posed by*

SAR Information

transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.”

- *Per paragraph 53, “...the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).”*
- *Per paragraph 73, “...the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term “direct” as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule....”*

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input checked="" type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
<input checked="" type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions	
<input checked="" type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input checked="" type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.

Reliability and Market Interface Principles

<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input checked="" type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards

Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards Standards Authorization Request (SAR)

Do not use this form for submitting comments. Use the [electronic form](#) to submit comments on the Project 2016-02 Modifications to CIP Standards SAR. The electronic comment form must be submitted by **8 p.m. Eastern, Thursday, April 21, 2016**.

Documents and information about this project are available on the [Project 2016-02 Modifications to CIP Standards](#). If you have questions, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

Background Information

On January 21, 2016, FERC issued [Order No. 822](#), *Revised Critical Infrastructure Protection Reliability Standards*, approving seven CIP Reliability Standards and new or modified definitions. FERC also directed NERC to develop modifications to address:

- Protection of transient electronic devices used at low-impact bulk electric system cyber systems;
- Protections for communication network components between control centers; and
- Refinement of the definition for Low Impact External Routable Connectivity (LERC)

FERC directed NERC to submit new or modified standards responding to the directives related to the definition of LERC by March 30, 2016, one year from the effective date of Order No. 822. FERC did not place any time frame for NERC to respond to the remaining directives.

The CIP Version 5 Transition Advisory Group (V5 TAG) transferred issues to the CIP Version 5 Standard Drafting Team (SDT) that were identified during the industry transition to implementation of the CIP Version 5 Standards. Specifically, the issues that the SDT will address are:

- Cyber Asset and BES Cyber Asset Definitions
- Network and Externally Accessible Devices
- Transmission Owner Control Centers Performing Transmission Operator Obligations
- Virtualization

On March 9, 2016, the NERC Standards Committee accepted and authorized the posting of the Modifications to CIP Standards SAR. It is posted for a 30-day informal comment period because it is addressing FERC directives.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Yes:

No:

Comments:

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Yes:

No:

Comments:

3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Yes:

No:

Comments:

CIP V5 Issues for Standard Drafting Team Consideration

September 15, 2015

From experience in the V5 Transition Study and the on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty in implementation of the requirements. In many cases, the V5TAG members found that select language within the CIP Version 5 standards may be understood in multiple ways. These interpretations appear to go beyond the intended flexibility of the standard language that is necessary to accommodate the diverse nature of facts and circumstances across the electric sector. At this time, the V5TAG proposes the following issues to be addressed by the CIP V5 Revisions drafting team (SDT) or other appropriate team for standards development:

- **Cyber Asset and BES Cyber Asset definitions**

The foundational definition for the CIP Version 5 standards is ‘Cyber Assets.’ When Cyber Assets meet a threshold of Bulk Electric System (BES) impact they become ‘BES Cyber Assets (BCA)’ which are grouped, by a Responsible Entity, into ‘BES Cyber Systems (BCS).’ Viewing BCAs too broadly can lead to many thousands of devices in the typical utility becoming an administrative burden for which few if any cyber security controls can actually be applied or where there is limited associated cyber security risk. Vast amounts of effort would be expended for these types of cyber assets to track and document their lack of capability for even the most basic cyber security controls. Viewing BCAs too narrowly could lead to missing consideration of devices that have a sufficient level of cyber capability and risk impact.

The SDT should consider the definition of Cyber Asset and clarify the intent of “programmable” by considering such factors as if a device is merely configurable, its executable code is not field upgradable, or if its functionality can only be changed via physical DIP switches, swapping internal chips, etc.

The SDT should consider clarifying and focusing the definition of “BES Cyber Asset” including:

- a. Focusing the definition so that it does not subsume all other cyber asset types. Protected Cyber Assets (PCA), by nature of being on the same network, can have some form of adverse impact if misused. Electronic Access Control or Monitoring Systems (EACMS) if misused or unavailable can have some form of adverse impact. This can result in a “hall of

mirrors” effect where everything in or that creates an Electronic Security Perimeter (ESP) also meets the BCA definition.

- b. Considering if there is a lower bound to the term ‘adverse’ in “adverse impact”. For example, is the focus of a typical generating unit the servers and operator human machine interfaces (HMI) and controller cabinets and Programmable Logic Controllers (PLCs) or is it the thousands of individual sensors and transmitters throughout the plant?
 - c. Clarify the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
- **Network and Externally Accessible Devices (ERC, ESP, IRA)**
The SDT should consider the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
 - a. Clarify the 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters.” When there is not an ESP at the location, consider clarity that the communication equipment considered out of scope is the same communication equipment that would be considered out of scope if it were between two ESPs.
 - b. The word ‘associated’ in the ERC definition is unclear in that it alludes to some form of relationship but does not define the relationship between the items. Striking ‘associated’ and defining the intended relationship would provide much needed clarity.
 - c. Review of the applicability of ERC including the concept of the term “directly” used in the phrase “cannot be directly accessed through External Routable Connectivity” within the Applicability section. As well, consider the interplay between IRA and ERC.
 - d. Clarify the IRA definition to address the placement of the phrase “using a routable protocol” in the definition and clarity with respect to Dial-up Connectivity.
 - e. Address the Guidelines and Technical Basis sentence, “If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.”
 - **Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations**
CIP-002-5.1 Attachment 1 – Impact Reliability Criteria, sections 1.1, 1.2, 1.3, 1.4, 2.11, 2.12, and 2.13 employ the language “used to perform the functional obligation of”, and then lists the functional registration. It was intended that this caveat would capture entities that perform obligations of a specific registered function, whether they are registered for that function or not. However, this language has caused confusion, especially in section 2.12 concerning TOP Control Centers. The term “functional obligation” may be interpreted to have different meaning in a variety of situations.

One interpretation is for the defined term Control Center to be strictly associated with the Balancing Authority (BA), Generator Operator (GOP), Reliability Coordinator (RC), and Transmission Operator (TOP) functional registrations, and that control rooms or dispatch centers owned and operated by Transmission Owners (TOs) with control of limited BES facilities would be excluded. A second interpretation may expand or contract the applicability of the Control Center designation, based on criteria that may not take into consideration overall risk to reliable operations of the BES.

Early analysis found the potential for TOs (not Registered as TOPs) that only operate limited breakers to be pulled in as medium impact Control Centers, even if the few Facilities they control are low impact. (For example, an entity with one 161kV breaker in one substation and a second 161kV breaker in a different substation, both breakers associated with low impact Facilities.) As currently written, low impact Control Centers are to be identified per criteria 3.1 and could be commensurate with risk for these scenarios.

Areas for the SDT to address are:

- a. CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.
 - b. Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the “CIP-002-5” section paragraph starting with “Responsibility for the reliable operation of the BES is spread across all Entity Registrations”; the table following that paragraph; the “High Impact Rating (H)” section; and the criterion bullets for Control Centers under the “Medium Impact Rating (M)” section.
 - c. The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include ‘Control Center’, for example, the revised Glossary term for “System Operator” to be effective July 1, 2016).
 - d. The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.
- **Virtualization**

The CIP Version 5 standards do not specifically address virtualization. However, because of the increasing use of virtualization in industrial control system environments, questions around treatment of virtualization within the CIP Standards are due for consideration.

The SDT should consider revisions to CIP-005 and the definitions of Cyber Asset and Electronic Access Point that make clear the permitted architecture and address the security risks of network, server and storage virtualization technologies.

The transition to CIP Version 5 continues as the compliance deadline of April 1, 2016 approaches. The V5TAG continues to discuss challenging issues being undertaken during the on-going implementation. The group may find additional issues to transfer to the SDT for consideration.

Standards Announcement

Project 2016-02 Modifications to CIP Standards Standards Authorization Request

Informal Comment Period Open through April 21, 2016

[Now Available](#)

A 30-day informal comment period for the **Project 2016-02** Standard Authorization Request (SAR), is open through **8 p.m. Eastern, Thursday, April 21, 2016**.

Commenting

Use the [electronic form](#) to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project

For more information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

North American Electric Reliability Corporation

3353 Peachtree Rd, NE

Suite 600, North Tower

Atlanta, GA 30326

404-446-2560 | www.nerc.com

Comments Received Report

Project Name: 2016-02 Modifications to CIP Standards SAR
Comment Period Start Date: 3/23/2016
Comment Period End Date: 4/21/2016
Associated Ballots:

There were 33 sets of responses, including comments from approximately 33 different people from approximately 32 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

- 1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.**
- 2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.**
- 3. Are there any other concerns with this SAR that haven't been covered in the previous questions?**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Florida Municipal Power Agency	Chris Gowder	3,4,5,6	FRCC	FMPA	Tim Beyrle	Florida Municipal Power Agency	4	FRCC
					Jim Howard	Florida Municipal Power Agency	5	FRCC
					Lynne Mila	Florida Municipal Power Agency	4	FRCC
					Javier Cisneros	Florida Municipal Power Agency	3	FRCC
					Randy Hahn	Florida Municipal Power Agency	3	FRCC
					Don Cuevas	Florida Municipal Power Agency	1	FRCC
					Stan Rzad	Florida Municipal Power Agency	4	FRCC
					Matt Culverhouse	Florida Municipal Power Agency	3	FRCC
					Tom Reedy	Florida Municipal Power Agency	6	FRCC
					Steve Lancaster	Florida Municipal Power Agency	3	FRCC
					Mike Blough	Florida Municipal Power Agency	5	FRCC
					Mark Brown	Florida Municipal Power Agency	4	FRCC

					Chris Adkins	Florida Municipal Power Agency	3	FRCC
					Ginny Beigel	Florida Municipal Power Agency	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southwest Power Pool, Inc. (RTO)	Jason Smith	2	MRO,SERC,SPP RE,WECC	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Ellen Watkins	Southwest Power Pool, Inc. (RTO)	1	SPP RE
					Terri Pyle	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Mike Buyce	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Robert A. Schaffeld	Southern Company - Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William D. Shultz	Southern Company - Southern Company Services, Inc.	5	SERC

					John J. Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6	NPCC	RSC No Dominion	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC

Glen Smith	Northeast Power Coordinating Council	4	NPCC
Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Brian Robinson	Northeast Power Coordinating Council	5	NPCC
Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
Alan Adamson	Northeast Power Coordinating Council	7	NPCC
Michael Jones	Northeast Power Coordinating Council	3	NPCC
Michael Forte	Northeast Power Coordinating Council	1	NPCC
Kelly Silver	Northeast Power Coordinating Council	3	NPCC
Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Edward Bedder	Northeast Power Coordinating Council	1	NPCC
David Burke	Northeast Power	3	NPCC

						Coordinating Council		
					Peter Yost	Northeast Power Coordinating Council	4	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michele Tondalo	Northeast Power Coordinating Council	1	NPCC
					Kathleen Goodman	Northeast Power Coordinating Council	2	NPCC
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
					Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
Colorado Springs Utilities	Shannon Fair	1,3,5,6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC

					Shannon Fair	Colorado Springs Utilities	6	WECC
--	--	--	--	--	--------------	----------------------------	---	------

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Bob Reynolds - Southwest Power Pool Regional Entity - 10

Answer No

Document Name

Comment

The SPP RE respectfully submits the following eight comments to the Project 2016-02 Standards Authorization Request: (1) With respect to clarifying or revising the definition of Cyber Asset, consider including misuse of the Programmable Electronic Device through misconfiguration or reconfiguration of the device in the instance that its behavior is affected and its altered behavior impacts the associated Facility. Consider the risk of misuse (i.e., how would someone misconfigure or reconfigure the device to cause undesired behavior) as appropriate. (2) With respect to clarifying or revising the definition of External Routable Connectivity (ERC), consider the point in the communication path at which a conversion from routable to non-routable communication protocol occurs. Is ERC only established if the conversion occurs in the same asset as the BES Cyber Asset or can ERC be established if the conversion occurs at the remote end of the communication path (e.g., conversion at the Control Center for communication to a serially connected relay in a substation)? Consider whether ERC exists only if the conversion occurs outside of an established ESP (i.e., there is no ERC if the device performing the conversion is inside an ESP and protected per the CIP Standards). (3) With respect to CIP-002-5.1, Impact Rating Criteria 3.2 and 3.3, clarify that the Low Impact BES Cyber Systems are associated with Facilities located within the asset as opposed to being associated with the asset itself. The opening statement in Section 3 of the Impact Rating Criteria states "BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets..." The SPP RE has already been presented with an argument that flow meters in a substation are not BES Cyber Assets because they are associated with a Transmission line and not the Transmission station or substation cited in Impact Rating Criterion 3.2. (4) With respect to Tie Line and other Transmission line flow meters, these Cyber Assets appear to have been unintentionally excluded from consideration under CIP-002-5.1, Impact Rating Criterion 2.5. Impact Rating Criterion 2.5 excludes consideration of BES Cyber Assets associated with Transmission lines through its use of "operating between 200 kV and 499 kV at a single station or substation" language. In the instance where the tie line or other flow meter is associated with a Transmission Line operated between 200 and 499 KV in a substation that satisfies the qualifications of Impact Rating Criterion 2.5, the meter will be excluded and not be categorized as Medium Impacting. Additionally, some entities are proffering the argument that the flow meter is not a BES Cyber Asset because its loss or misuse will not affect the reliable operation of the Transmission Facilities in the substation where the meter resides, overlooking the impact the loss of meter information may have on Control Center operations including ACE calculation, security-constrained generation dispatch, AGC, and Situational Awareness. An additional Criterion, specific to Transmission line flow meters, may be required to address this issue. (5) With respect to Physical Security Perimeters and their associated Requirements, clarification is needed regarding the concept of zoned access within a defined PSP. Specifically, is it acceptable to define an overarching PSP and then establish areas of access control within the defined PSP where BES Cyber Systems are present and for which different access permissions are established? For example, can a building containing a Control Center and its associated data center be declared a single PSP while access controls are established that do not permit all personnel with authorized unescorted access into the building to have authorized unescorted access into one or more access control zones within the building (e.g., the data center). And, if the zoned access areas are deemed to be independent PSPs, would the application of CIP-006-6 R1 Part 1.3 require two access controls to enter the interior PSP containing High Impact BES Cyber Systems, or would the requirement for two access controls to enter the outer (building) PSP suffice such that a single access control is permitted for the interior PSPs? (6) In consideration of the results of the investigation of the Ukraine cyberattack, the SPP RE recommends that Cyber Assets outside of the ESP with a machine-to-machine connection to a Cyber Asset inside the ESP be subjected to the same controls as the Intermediate System. There is a gap in the Standards today whereby a communication protocol typically used for interactive access (e.g., FTP, SSH, web services) can also be used for system-to-system communication. While Interactive Remote Access requires the use of an Intermediate System, encryption, and multi-factor authentication to the

Intermediate System, system-to-system communication using the exact same protocols do not require such controls. The Electronic Access Point cannot tell the difference, thus a successful compromise of the Cyber Asset residing outside of the ESP affords the attacker trusted access into the ESP. (7) In consideration of the results of the investigation of the Ukraine cyberattack, the SPP RE recommends the Standards Drafting Team consider whether essential support systems (UPS, PBX/VOIP phone, fire suppression, emergency generation) should be afforded certain protective controls to mitigate the risk that a successful attack directed at the support systems would adversely impact the asset containing BES Cyber Systems. For example, one element of the Ukraine attack was directed at a network-connected Uninterruptible Power Supply, removing power from essential Cyber Assets. (8) The SPP RE understands that a number of Requests for Interpretation have been submitted against CIP Version 5. While NERC staff has stated publicly that the RFIs would be addressed by the Standards Drafting team, there is no mention of RFIs in the Standards Authorization Request. To the extent that there are RFIs not included in either the Order 822 or V5TAG items, the Standards Authorization Request should state that pending RFIs will be considered and addressed in any revisions to the CIP standards.

Likes 0

Dislikes 0

Response

Steven Parker - EnergySec - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

We recommend that the term, Adverse Impact, contained within the BES Cyber Asset definition be itself added as a defined Glossary term. Any attempt to clarify this phrase by adding language within the BES Cyber Asset definition is likely to complicate, rather than simplify, understanding of the term.

The current outstanding Requests For Interpretation should be added as issues to be addressed by the Standards Drafting Team under this SAR. Per the Standards Process Manual, Section 7, Interpretations “shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard.” Although this statement does not directly apply to the currently open, and unresolved, Requests for Interpretation, we believe the most logical approach would be to address the identified issues via this SAR rather than a separate interpretation development effort.

We recommend that the scope of the SAR be expanded to address the increasing use of 3rd party (i.e. cloud) services. Numerous utilities are leveraging new capabilities available from 3rd party providers in ways that enhance the overall security of the grid. Examples include cloud-based vulnerability scanners, offsite log monitoring services, cloud-based malware analysis and threat detection, cloud-based network monitoring, and colocation facilities. Unfortunately, the current standards are unduly prohibitive towards these services and as a result may be lowering the overall security of the grid by discouraging the use of effective, cutting edge tools, techniques, and services. For example, CIP-006 requires EACMS devices to be within a Physical Security Perimeter. It is not clear how, or if, this requirement can be met for cloud services. The SDT should review existing language and add, modify, or remove language as needed to accommodate any such services that can be prudently deployed to enhance overall grid security.

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer No

Document Name

Comment

Xcel Energy has some concern that the SAR's inclusion of communication network components between control centers could extend to cabling between Control Centers. The inclusion of cabling between Control Centers would be in direct contrast to guidance in the CIP standards and the authority granted in section 215(d)(5) of the FPA by asking entities to be held accountable for equipment they do not own. Communication networks between discrete Electronic Security Perimeters (ESPs) have been excluded from the CIP standards. Additionally, it is unclear how physical protection of cabling would afford any additional protection to networks already in compliance with the suite of CIP standards. Furthermore, the documentation of any physical protection would be administratively burdensome without adding any additional protection.

If any requirement is to be added regarding cabling between Control Centers, we would encourage the drafting team to add it as logical controls such as encryption or other such measures under CIP-005 and/or CIP-007. To require physical protection of equipment not owned by Registered Entities seems in direct contrast to previous guidance, outside of the authority documented in section 215(d)(5) of the FPA and add administrative burden with little value.

Likes 0

Dislikes 0

Response

Ginny Beigel - City of Vero Beach - 9

Answer No

Document Name

Comment

See response to Question 3.

Likes 0

Dislikes 0

Response

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
<p>SMUD respectfully suggests an addition to the objective for this SAR be modified to include addressing single points of failure in communication networks and network equipment that meet the definition of the BCA where this equipment is outside of the ESP but contained within the Facility.</p>	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
<p>Seminole concurs with all items currently listed in the draft Standards Authorization Request. Seminole recommends that additional items should be included in the SAR</p> <p>The industry has received guidance from NERC's Compliance Monitoring and Enforcement group in the form of Frequently Asked Questions and Lessons Learned. These guidance items need to become formal Guidelines, with appropriate Technical Basis, and placed within the Standards and approved by the NERC membership</p> <p>Issues related to Shared Facilities that are not adequately addressed in the standards. Specifically, when multiple entities have BES Cyber Assets residing at a shared location, there is no clear delineation of responsibility. Without defined responsibilities in the Standard, there is also no documented process to determine who has responsibility and to document those responsibilities. CFRs, JROs, MOUs, and other contractual agreements have been discussed as possible solutions to this issue. However, at a minimum, clear formal Guidelines should be added to CIP-002-5.1. Additional guidance should be added where appropriate.</p> <p>Based on experience of both the V5TAG and of entities preparing for the standards, it is clear that significant updates are needed to the Guidelines and Technical Basis for all CIP Reliability Standards.</p>	

Based on these comments, Seminole recommends adding language to address the following items:

1. **Guidelines and Technical Basis** – As core information used by Entities to ensure a consistent understanding of requirements and based on Lessons Learned by Entities, Reliability Standards CIP-002 through CIP-011 are authorized for modification by the Standards Development Team and submitted for ballot to the NERC Ballot Body. These clarifications should minimally consider
 - i. Lessons Learned and FAQs published by NERC and Regional Compliance
 - ii. Items that may be determined unsupported by the standard and definitions (i.e. BES Reliability Operating Services); and
 - iii. Industry practices that have evolved from industry’s compliance efforts.
2. **Paragraph 51 option** - Option to consider removal of Requirement Parts in specific cases considering the same guidelines as those used in the Paragraph 51 project.
3. **Definitions of Low Impact External Routable Connectivity AND External Routable Connectivity** - Consider modifying the definitions of External Routable Connectivity and LERC to ensure consistent language and communication of both ERC and LERC definitions
4. **Definitions of Cyber Asset, BES Cyber Asset (BCA), and BES Cyber System (BCS)** – The SAR should also authorize changes to clarify the definition of BES Cyber System, specifically whether BES Cyber Systems include any Cyber Asset type other than a BCA (such as PCA, EACMS, PACS)
5. **Measures and Audit Expectations** - Using information provided by the NERC Compliance Monitoring group as one source of information, the measures section of all requirements and requirements parts should be reviewed and updated as necessary to ensure that an entity who provides the evidence listed in the measure is able to fully demonstrate compliance under normal circumstances.
6. **Exceptional Circumstances** - Recommend formalizing guidance for Exceptional Circumstances in a single location.

Likes 0

Dislikes 0

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer

No

Document Name

Comment

ATC is a member of EEI and supports the comments submitted by the EEI CIP Standards Subgroup related to the draft SAR.

Likes 0

Dislikes	0
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
<p>The Edison Electric Institute (EEI) submitted comments relating to this SAR. Their comments address scope and objectives of the SAR for consideration by the Standards Drafting Team. Kansas City Power & Light Company endorses and incorporates by reference the comments submitted by EEI.</p>	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6 - NPCC, Group Name RSC No Dominion	
Answer	No
Document Name	
Comment	
<p>Request that the scope of virtualization be expanded beyond only CIP-005. Want to remind the SDT that communications between Control Centers usually involves third parties that tend to be outside of FERC's jurisdiction.</p>	
Likes	0
Dislikes	0
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	

Comment

The phrase “control centers” in the “Industry Need” section which lists the FERC directives has not been capitalized. FERC Order 822 uses “bulk electric system Control Centers” when speaking about this directive. Tri-State believes the SAR should use that same language used by FERC in order to accurately represent what is expected to be in scope of this project.

There is also an error in the “Reliability Functions” section. “Transmission Service Provider” is checked off instead of “Distribution Provider”. The new versions of the CIP standards do not include Transmission Service Providers, but do include the Distribution Providers.

Likes 0

Dislikes 0

Response

Mike Smith - Manitoba Hydro - 1,3,5,6

Answer

No

Document Name

Comment

Virtualization: Manitoba Hydro does not agree with NERC prescribing specific system architecture, technologies or designs. The SDT should continue to focus on identifying requirements to meet specific security objectives for the virtualization.

Protections for communication network components between control centers: Please clarify the scope of Control Centers. Does it refer to the communication links between all Control Centres cross entities such as the link between RC Control Center and TOP Control Centre or only the Control Centers within the resposbile entity.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

No

Document Name

Comment

FMPA is concerned that the Project 2016-02 SAR is too narrowly focused. There are a number of issues with the current CIP Standards, mostly concentrated in CIP-002-5.1. The SAR should be written to allow the drafting team to consider how the suite of CIP standards work together. CIP-002-5.1 is the foundation of the remainder of the CIP requirements. Narrowly scoping this SAR just prolongs dealing with these problems, and ties the drafting team's hands should they identify other concerns. Also, ignoring these issues now will cause more revisions, which in turn will add to the pervasive confusion and uncertainty already surrounding the CIP standards. The industry needs clarity and resolution to these matters in order to be assured their efforts to comply are effective and that companies understand their investments are going to the right places.

The following additional items should be considered by the SDT:

- 1) Section 4.2.2 states "All BES Facilities" as being subject to the standards for all Responsible Entities except for DP's. This effectively negates the rest of the requirements, as anything that qualifies as a "Cyber Asset" could not possibly be a "Facility" as well. The language is missing the "Cyber Assets" component. Suggested language would be "Cyber Assets at all BES Facilities".
- 2) Ownership isn't properly accounted for in the requirements. Shared facilities (generally speaking substations) often involve multiple entities that own equipment, who may or may not be Responsible Entities as described in CIP-002-5.1. There should be specific language requiring the owner of the equipment to communicate with the owner of the Facility.
- 3) Clarify what is meant by "associated with" in the context of the Impact Rating Criteria in CIP-002-5.1 – Attachment 1. Clear up the inconsistencies in the requirements between the use of "associated with" (criterion 2 & 3 in Attachment 1) in some areas and "used by and located at" (criterion 1 in Attachment 1) in other parts. Have a process developed for ensuring entities notify if there are devices owned by a different entity that are "associated with" their BESCS (for example, a meter that one entity needs for the reliable operation of their Control Center that isn't owned by them).
- 4) Leasing equipment is a loophole in the requirements based on the language in section 4.2. This should be fixed so an entity isn't able to lease equipment and avoid meeting CIP requirements.
- 5) The scope of equipment applicable to CIP due to applicability to other NERC standards (such as CIP-002-5.1 Section 4.2.1.3) should be clarified further. For example, a "Protection System" can be made up of multiple devices owned by multiple entities. If an entity owns a component of a Protection System that isn't a Cyber Asset, they shouldn't have to meet CIP requirements.
- 6) Voice over Internet Protocol (VoIP), much like virtualized servers and environments, is not discussed in the CIP requirements. VoIP telephony devices should be excluded from the requirements unless they are networked with other BESCS, in which case they could become protected CA's.
- 7) There is no mention of "data at rest" in this SAR, although it was clearly part of Order 822 (paragraph 56 – "NERC's response to the directives in this Final Rule should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted **or at rest**").
- 8) CIP-002-5.1 should be re-written to make sure all assets are properly identified. For example, under R1 of CIP-002-5.1, a Responsible Entity is only required to find Cyber Assets at each of the six locations listed under R1. However, in Attachment 1 for medium and low impact, the language of "associated with" is introduced, indicating that there could be assets/locations containing Cyber Assets that are not part of the list of six asset types listed under R1. The approach taken by R1 is not the one being recommended by NERC or the Regional Entities. The standard should be revised to clarify the relationship between the six asset types/locations in R1 and the "used by and located at"/ "associated with" language in Attachment 1.

Likes	0
Dislikes	0

Response

Matt Stryker - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
<p>The SAR should be modified to include the following language and scope: Update obsolete references to NERC defined terms or standards through modifications to the CIP standards. References which are obsolete or require clarification include, but are not limited to:</p> <ul style="list-style-type: none"> To improve consistency within Registered Entity compliance programs, phrasing in CIP-002-5.1 Requirement 1 and Attachment 1 referencing undefined or unclear terms or phrases such as “Transmission stations and substations”, “generation interconnection Facilities”, “Systems and facilities critical to system restoration”, “Generation resources”, “BES reactive resource or group of resources” should be removed by the SDT and instead reference the FERC approved definition of Bulk Electric System (BES) which now included clear and defined qualifications for inclusion and exclusion of these assets as well as an appeals process to address exceptions. An example would be changing the following language: <ul style="list-style-type: none"> R1.ii. Stations and Substations containing BES Facilities R1.iii BES Generation Facilities RAS: Phrasing in CIP-002-5.1 Applicability, Requirement 1, and Attachment 1 referencing variations of Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements should be clarified and simplified by the SDT to reference the new Remedial Action Scheme (RAS) definition which FERC approved 11/19/2015. The current PSP definition should be clarified by the SDT to address that it should not apply to assets in CIP-006-6 Part 1.1 simply because they may be secured in a location which meets the PSP definition: “The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.” Interactive Remote Access definition: The SDT should clarify the phrase “system-to-system process communications” to address scripts or batch operations performed on-demand or on a periodic basis as not meeting the definition. The phrase “Collector Bus” as it appears in Attachment 1, Criteria 2.4 and 2.5 should be defined by the SDT. The guidance document references a report (<i>Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface</i>) which predated the adoption of the NERC BES definition and has not been picked up for development since. The BES definition provides additional clarification of the applicability to multiple generation scenarios in I2, I4, E1, E2, E3, and E4. Notably, CIP-014-1 does provide a diagram of the collector bus, but does not include an associated definition. Attachment 1, Criterion 2.4: Clarify if the Transmission Facilities operated at 500kV or higher are “at a single station or substation” to make the language and application consistent with Criterion 2.5 to correctly scope BES Cyber Assets. Clarify CIP-002-5.1 R1.vi for Registered Entities registered for additional functions other than Distribution Providers. Revising the language of CIP-002-5.1 R1.vi. to state “<i>For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above at assets which have not already been considered under Ri-Rv</i>” would be a possible solution. 	
Likes	0
Dislikes	0
Response	

Shannon Fair - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities agrees with the scope of the SAR.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
The Bureau of Reclamation believes that the proposed Standards Authorization Request addresses FERC directives in Order No. 822. Reclamation also supports NERC efforts to address the issues identified by the CIP Version 5 Transition Advisory group.	
Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer

Yes

Document Name

Comment

Idaho Power agrees with the items that are currently scoped into the SAR, but also believe it does not go far enough. There are numerous areas within the v5/v6 standards where clarifications need to be made. Idaho Power doesn't think that a full re-write of all of the CIP standards is prudent as it will create continued churn in the industry. Idaho Power believes there should be continual slow improvement in the standards and not large swings that create guidance gaps from the regulators and understanding gaps from the industry.

The proposed scope does not include a change to the applicability columns to tier ratings (i.e., medium with and without ERC). These need to be more explicitly split out as they create odd breakdowns in the standards that seem to be creating inconsistencies in the standards. For example, under CIP-010-2 R4 Attachment 1, R1.2 requires authorizations for all Transient Devices and R3.1 for removable media for Medium Impact BCS. However, Medium Impact BCS without external routable connectivity (ERC) do not require an authorization records under CIP-004, specifically R4.1. This means the critical devices/systems themselves have no authorization requirements, but the transient devices and removable media associated with them do. A second example is information protection for Medium Impact BCS without ERC. CIP-011-2 requires information protection policies/procedures be applied equally to all Medium Impact BCS, which includes protecting it in storage, transit, and use. However, once again, there are no requirements to authorize an individual to gain access to "designated storage locations" under CIP-004-6 Part 4.1.3. This means the information needs to be protected, but only those Medium BCS with ERC have to have individuals get authorized for access to the information. This seems consistent with not authorizing individuals to get access to Medium Impact BCS without ERC but not with applying information protection policies to one tier of Medium Impact BCS.

The SDT should consider four risk tiers rather than three if they are going to treat ERC and non-ERC separately in the standards. These are simply two examples of inconsistencies that have been created by trying to treat them within the same "medium" risk tier. There could still be similar requirements that would be applied to a Medium Impact BCS with ERC and a Medium Impact BCS without ERC, but inconsistencies would be more easily identified by breaking out the Medium BCS tier and the Medium without ERC.

The proposed scope does not include changes to CIP-002-5.1. CIP-002 has several inconsistencies and logic issues and no clearly delineated process allowing no clear way to comply with the standard other than simply deciding on a direction and hoping the regional entity is okay with your approach. The wording and processes required by CIP-002 need to be refined and clarified to make the expectations more clearly known. For example, the Guidelines and Technical Basis state, "The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1. This reference to use of the BROS is stated as an option that may be useful in identifying BCAs/BCSs. Nowhere in CIP-002 the definition of BCA or BCS does it speak directly to the BROS. The only loose tie-in is that the definition of BCS talks about reliability tasks, which FERC, in Order 791, clarified they believed it alluded to the NERC Functional Model, which relates to the high-level responsibilities of registered entities. However, it seems regions are beginning to take a stance that BROS is the hard-line approach as the only acceptable way to approach identification of CIP assets and BCAs/BCSs. Additionally, the wording of the CIP-002 standard does not ever specifically state that an entity needs to identify Protected Cyber Assets (PCAs), Electronic Access Control or Monitoring System (EACMS) or Physical Access Control Systems (PACS), yet the standards expect that entities will know what those devices are in order to apply specific requirements to them. Entities should not have to read between the lines when trying to comply with mandated compliance standards. Doing so creates confusion, inconsistencies, and distrust between the regulators and the industry who should be working together to meet common objectives.

Likes	0
Dislikes	0
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
<p>ERCOT recommends that <i>Project 2016-02 – Modification to CIP standards</i> be limited to 1.) clarifying existing language,2.) addressing the V5 TAG issue list, and 3.) incorporating the FERC-directed changes discussed in FERC Order No. 822. Introducing new concepts through substantive language changes in this iteration would be premature. In order to allow CIP Version 5 and 6 concepts to be fully implemented, any proposed substantive changes should be reserved for future CIP standards projects.</p>	
Likes	0
Dislikes	0
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
<p>Although Austin Energy (AE) agrees with the SAR's objectives, we urge the SDT to proceed with caution. Registered Entities are just now reaching compliance with the Version 5/6 Standards. Unless a device truly creates risk to the BES, we should not include it in the CIP Standards' scope.</p>	
Likes	0
Dislikes	0
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name

Comment

Arizona Public Service (AZPS) appreciates the opportunity to comment on the proposed SAR. Although AZPS generally supports the scope as described in the SAR, we believe that there are additional clarifications that should be considered beyond those detailed in the FERC Order 822 and the CIP Version 5 Transition Advisory Group (V5TAG) considerations.

AZPS believes the industry would benefit from clarification of the definition of the following terms:

- Transmission Facility – Transmission Facility is not a defined term. Although Facility is a defined term, AZPS does not believe that the Facility definition aligns with the standard’s intent. AZPS suggests that a definition be provided by the Standard Drafting Team (SDT).
- Programmable - The SDT should consider defining programmable to clarify that a device would not be included simply because it was configurable, e.g., has functionality that can be changed locally.

AZPS would also like to suggest that the SDT clarify the intent of the grouping BCAs into BCS by leveraging the logically based perimeter security controls at the Electronic Security Perimeter (ESP) as well as local, device specific security controls per each BES Cyber Asset’s (BCA) capability.

AZPS would also like to add some additional comments to the discussion in the V5TAG CIP V5 Issues for Standard Drafting Team Consideration document.

- AZPS recommends that the SDT consider not defining “adverse impact” or defining a lower bound thereof within the definition of BES Cyber Asset, but to revise the body of CIP standards and/or applicable defined terms to utilize already defined terms such as “Adverse Reliability Impact.” Such would facilitate consistency as well as clarity regarding the N-1 contingency issue and other issues regarding that term identified by the V5TAG.
- AZPS believes that when BES Cyber Assets (BCA), such as relays, RTUs, and others, are connected via serial links to IP converters and/or IP-enabled security gateways, it would be appropriate to consider those elements downstream of the security gateways as BCA that do not have External Routable Connectivity (ERC). This is appropriate because the IP- converters and/or IP-enable security gateways require authentication and provide a protocol break. AZPS believes accurate and timely guidance related to serially connected devices supports the overall goal of providing appropriate and effective cyber security controls; thus, improving reliability.
- AZPS supports the CIP V5TAG analysis regarding virtualization. Virtualization is an effective tool for utilities and consideration should be given to ensuring that flexibility is maintained. An approach should consider the required outcome rather than the specifics of how that outcome is achieved.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,5,6 - MRO,WECC,Texas RE,SERC,SPP RE,RF

Answer	Yes
Document Name	
Comment	
Look to NIST 800-125 for virtualization security.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,6,7 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Sistrunk - Small End-Use Electricity Customer - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Richard Vine - California ISO - 2

Answer No

Document Name

Comment

No comment

Likes 0

Dislikes 0

Response

Matt Stryker - Georgia Transmission Corporation - 1 - SERC

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPPA

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Warren Cross - ACES Power Marketing - 1,3,5,6 - MRO,WECC,Texas RE,SERC,SPP RE,RF	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6 - NPCC, Group Name RSC No Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Puztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chris Sistrunk - Small End-Use Electricity Customer - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,6,7 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginny Beigel - City of Vero Beach - 9	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Parker - EnergySec - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Reynolds - Southwest Power Pool Regional Entity - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Fair - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

--

3. Are there any other concerns with this SAR that haven't been covered in the previous questions?

Warren Cross - ACES Power Marketing - 1,3,5,6 - MRO,WECC,Texas RE,SERC,SPP RE,RF

Answer No

Document Name

Comment

The SDT should prioritize the issues based on whether it is associated with a FERC directive or not. For issues that are not directed by FERC, there may need to be additional time to find a resolution associated with these issues. The only deadlines on this project are related to the FERC directives.

Likes 0

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Bob Reynolds - Southwest Power Pool Regional Entity - 10

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Erika Doot - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Parker - EnergySec - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	2016-02_CIP_SAR_Unofficial_Comment_Form_ERCOT draft.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP RE, Group Name SPP Standards Review Group	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Stryker - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	

Comment	
Likes	0
Dislikes	0
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
<p>Burns & McDonnell appreciates the opportunity to comment on the Standard Authorization Request (SAR) titled “Modifications to CIP Standards” with the following input:</p> <p>The V5TAG recommended the Standard Drafting Team (SDT) consider Virtualization as part of the SAR due to the increased use of this technology in industry control system environments. Burns & McDonnell is recommending the Virtualization section of the SAR be amended to indicate that the SDT not only consider virtualization technology usage by Responsibility Entities (Entity) which they own and operate, but usage of similar technology not owned or operated by an Entity. Increased interest in “cloud” based services such as Software as a Service (SaaS) and Platform as a Service (PaaS) have created questions on the application of the standards with no guidance on how they should be applied. Cloud usage of virtual technology is similar to Entity owned usage of the same technology, but Burns & McDonnell feels it is important that both usage conditions be considered and any differences in approach be indicated in any final SDT work product. Burns & McDonnell does not believe a separate section should be created for “cloud” usage, but the SAR section on Virtualization could be updated to cover virtualization technology owned by or usage of services by an Entity. One recommendation for the re-wording is:</p> <p>The CIP V5 standards do not specifically address virtualization. Because of the increasing use of virtualization in industrial control system environments either owned and operated by a Responsible Entity, or from a service provider who owns and operates the environment under the service providers control, V5TAG asked that the SDT consider CIP-005 and the definitions of Cyber Asset and Electronic Access Point regarding permitted architecture and the security risks of network, server and storage virtualization technologies under these two type of conditions.</p>	
Likes	0
Dislikes	0
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	

Comment

Currently there are no specific requirements or guidelines included within the NERC CIP Reliability Standards v.5/6 relating to utilization of the cloud. Based on discussions with the regional auditing body, it has been agreed upon that utilization of the cloud for storage of BES Cyber System Information may be sufficiently secured through field level packet encryption with the responsible entity only holding the private key. It would be in the interest of the California ISO for there to be a provision included within the NERC CIP Reliability Standards addressing cloud scenarios.

Likes 0

Dislikes 0

Response

Ginny Beigel - City of Vero Beach - 9

Answer

Yes

Document Name

Comment

We belong to the FMPA municipal organization and have arrived at a consensus with the help of one of its SMEs who is immersed in CIP Standards. Comments follow below:

The SAR falls short of fixing a lot of the core issues related to CIP-002-5.1. The following additional items should be addressed by the SDT:

- 1) Section 4.2.2 states "All BES Facilities" as being subject to the standards for all Responsible Entities except for DPs. This effectively negates the rest of the requirements, as anything that qualifies as a "Cyber Asset" could not possibly be a "Facility" as well. The language is missing the "Cyber Assets" component. Suggested language would be "Cyber Assets at all BES Facilities."

- 2) Ownership isn't properly accounted for in the requirements. Shared facilities (generally speaking substations) often involve multiple entities that own equipment, who may or may not be Responsible Entities as described in CIP-002-5.1. There should be specific language requiring the owner of the equipment to communicate with the owner of the Facility.

- 3) Clarify what is meant by "associated with" in the context of the Impact Rating Criteria in CIP-002-5.1 – Attachment 1. Clear up the inconsistencies in the requirements between the use of "associated with" (criterion 2 & 3 in Attachment 1) in some areas and "used by and located at" (criterion 1 in Attachment 1) in other parts. Have a process developed for ensuring entities notify if there are devices owned by a different entity that are "associated with" their BESCS (for example, a meter that one entity needs for the reliable operation of their Control Center that isn't owned by them).

4) Leasing equipment is a loophole in the requirements based on the language in section 4.2. This should be fixed so an entity isn't able to lease equipment and avoid meeting CIP requirements.

5) The scope of equipment applicable to CIP due to applicability to other NERC standards (such as CIP-002-5.1 Section 4.2.1.3) should be clarified further. For example, a "Protection System" can be made up of multiple devices owned by multiple entities. If an entity owns a component of a Protection System that isn't a Cyber Asset, they shouldn't have to meet CIP requirements.

6) Voice over Internet Protocol (VoIP), much like virtualized servers and environments, is not discussed in the CIP requirements. VoIP telephony devices should be excluded from the requirements unless they are networked with other BESCS, in which case they could become protected CA's.

7) There is no mention of "data at rest" in this SAR, although it was clearly part of Order 822 (paragraph 56 – "NERC's response to the directives in this Final Rule should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted **or at rest**").

8) CIP-002-5.1 should be re-written to make sure all assets are properly identified. For example, under R1 of CIP-002-5.1, a Responsible Entity is only required to find Cyber Assets at each of the six locations listed under R1. However, in Attachment 1 for medium and low impact, the language of "associated with" is introduced, indicating that there could be assets/locations containing Cyber Assets that are not part of the list of six asset types listed under R1. The approach taken by R1 is not the one being recommended by NERC or the Regional Entities. The standard should be revised to allow for the proper capture of all Cyber Assets either ONLY at the six asset locations, OR both at these locations as well as any other associated location.

Likes 0

Dislikes 0

Response

Diana McMahon - Salt River Project - 1,3,6,7 - WECC

Answer

Yes

Document Name

Comment

For network and externally accessible devices, SRP agrees with improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA). However, SRP has additional concerns.

Although much of CIP-005-5 is compatible to CIP V3 requirements, it does include a new requirement related to IRA for High Impact BES Cyber Systems and Medium Impact BES Cyber Systems with ERC. R2.1 states: *Utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.*

Based on R2.1 and the defined terms, demonstrating compliance with this requirement fundamentally requires evidence of two items:

1. That an Intermediate System is utilized such that the Cyber Asset initiating IRA does not “**directly access**” an applicable Cyber Asset; and
2. That technology for facilitating IRA meets the definition of an Intermediate System.

Issues with #1 – Ambiguity of “Directly Access”

In SRP’s experience the ERO and Regional Entities have used undefined terminology such as “protocol break”, “OSI layer 7 application break”, “session break” and others to describe what is intended by or compliant with the phrase “does not directly access”. However, SRP believes these terms mean different things to different subject matter experts and auditors. FERC articulated as much in Order 822. Although this issue has focused on LERC/LEAP requirements for low impact assets, the same ambiguity exists in the requirements for high/medium impact facilities. Where standards are unclear or ambiguous, entities are typically afforded flexibility in their compliance approaches. However, SRP believes the ERO has taken a rather prescriptive view of these requirements where reasonable people could easily differ in their interpretation. These ambiguities in defined terms and requirements need to be addressed by the SDT.

Issues with #2 – Ambiguity on acceptable Intermediate Systems

As noted in the Glossary of Terms, an Intermediate System is an Electronic Access Control or Monitoring System (EACMS). That notwithstanding, the ERO and Regional Entities have articulated rather informally and only fairly recently a need to assess each Intermediate System against the definition of BES Cyber Asset. This creates the potential for the proverbial “hall of mirrors” result, in the sense that individuals can rationalize a circumstance where seemingly all Cyber Assets (PACS, EACMS, other) could, under some scenario qualify as a BES Cyber Asset. SRP believes this was clearly not the intent of the Standard Drafting Team, and SRP does not believe this concept was considered for Intermediate Systems evaluated during the CIP V5 pilot project.

Most specifically, an entity that was on the drafting team and participated in the implementation pilot project with no issues was “surprised” with the Regional Entity’s assessment of compliance on this subject at time of audit. There is clearly a disconnect that needs to be addressed.

Architectures to support Interactive Remote Access to high, medium impact control centers, transmission stations and generation resources are very costly. Current ambiguity could cause extensive and rework for high and medium impact systems, and be even more impactful if similar architectures are applied to low impact assets.

The Standards Drafting Team (SDT) must clearly define the term “direct access” for high and medium facilities, ensuring “direct access” has same meaning for low impact facilities as ordered by FERC in its approval of the CIP V5 revisions. To the extent different controls are appropriate for high/medium vs. low impact systems, those distinctions must be clear in the language of the standard. SRP further recommends the SDT re-evaluate the definitions of Interactive Remote Access, Intermediate System, and BES Cyber Asset to ensure entities have a clear understanding of the security and compliance expectations associated with the standards.

Likes	0
Dislikes	0
Response	
Chris Sistrunk - Small End-Use Electricity Customer - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
<p>I believe that the CIP standards do not properly address security monitoring of networks (routable and non-routable). In my experience in the security industry that breaches (like electric disturbances) are inevitable, even for control systems. It's a matter of when, not if. The Security Event Monitoring logging requirements in CIP 007-5 R4 is a start, but I don't believe this data (4.1.1. Detected successful login attempts; 4.1.2. Detected failed access attempts and failed login attempts; 4.1.3. Detected malicious code.) provides enough digital forensic evidence in the aftermath of an intrusion or even a cyber attack. Also, the retention period in 4.3 of a minimum of "90 consecutive calendar days" is not sufficient. According to the 2016 M-Trends Report from FireEye (https://www2.fireeye.com/rs/848-DID-242/images/Mtrends2016.pdf), the median time of network compromise to discovery of the attacker is 146 days. If a utility only kept 90 days of logs, then it's quite possible that they won't have the forensics data to determine if the attacker used stolen credentials or malicious code. Also, many utilities don't use authentication or encryption with their Control System Protocols such as DNP3, ICCP, and Modbus. If an attacker were to spoof, replay, or modify the SCADA traffic, this would not be detected by the current set of monitoring and logging requirements.</p> <p>However, IT security best practice of network security monitoring (NSM) does provide sufficient network forensics data. NSM is similar to the type of monitoring and visibility required by NERC PRC 002-2 Disturbance Monitoring and Reporting standard. I wrote a blog post (https://www.linkedin.com/pulse/comparing-nerc-disturbance-monitoring-reporting-network-sistrunk) about the similarities between PRC 002-2 and NSM...and how NERC CIP 007 R4 could be improved to provide a bit more forensics data. Collecting NSM type data such as Session Data (timestamp, source IP address, source port, destination IP, destination port at a minimum) does not require a lot of storage space and would provide a better level of visibility. Collecting a shorter time period of full network packet captures for High or Medium BES Cyber Systems (including non-routable dial-up access) also is not very complicated, as IT systems have been doing this a long time.</p> <p>Since BES systems are becoming more connected, we cannot ignore network security monitoring in the future. I hope it doesn't take a serious cyber incident to convince the need for monitoring...much like the 1965 and 2003 blackouts convinced us to do disturbance monitoring. I know we haven't had a cyber attack that caused a power outage here in North America, but as an Electrical Engineer who has worked in the electric utility industry, now representing the ICS security industry, and also a customer, I want to help ensure that this doesn't happen.</p>	
Likes	0
Dislikes	0
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy requests that the SDT consider revisiting the transfer of employees and the requirement to remove access for that employee in 1 calendar day which may be viewed as overly burdensome. While this may be outside the scope of this particular SAR, we feel that since the project is regarding revisions to CIP standards, that we would be remiss not to request further discussion around this topic.	
Likes 0	
Dislikes 0	
Response	
Andrew Puztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC is a member of EEI and supports the comments submitted by the EEI CIP Standards Subgroup related to the draft SAR. Please review for applicability to this question.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE noticed there is a statement on page 4 which says the compliance deadline is April 1, 2016. This has been moved back to July 1, 2016.	

Likes	0
Dislikes	0
Response	
Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
<p>In addition to the issues addressed by the SAR, the Edison Electric Institute, on behalf of our members, recommends that the proposed project also consider the following ten issues:</p> <p>Issue 1: CIP Exceptional Circumstances</p> <p>A CIP Exceptional Circumstance is defined as:</p> <p>“A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.”</p> <p>We appreciate the understanding and recognition for the need to enable provisions for CIP Exceptional Circumstances. However, during implementation of CIP V5, it has become apparent that the CIP Exceptional Circumstances provision may need to be added to several requirements. Below are a few situation-based examples:</p> <ul style="list-style-type: none"> • <i>Risk of injury or death:</i> CIP-004-6 R2 and R4 allow for CIP Exceptional Circumstances to waive the need for Training and the Authorization based on need to be waived during such circumstances. We believe that CIP-004-6 R3 also should allow for CIP Exceptional Circumstances because the requirement to obtain a Personal Risk Assessment takes additional time that would hinder the ability of first responders to enter a Physical Security Perimeter in the event of the need for life saving measures. This would be consistent with CIP-004-3 “except in specified circumstances such as an emergency.” • <i>Impediment of large scale workforce availability:</i> CIP-007-6 R2 Security Patch Management requirements may be difficult to meet in the event that a major storm impacts a responsible entity, which requires all employees to report for storm duty for restoration efforts. • <i>Natural disaster:</i> CIP-006-6 R1 Part 1.4 monitoring may not be possible if the physical access point to a PSP is under water or destroyed by a storm. Similarly, Part 1.3 causes compliance issues if for example, a fire renders a PACS controller panel inoperable and the PSP access points have failed secure. Emergency response may have to use a physical key, mechanical lock, or an axe to gain access. Without the IAC language or CIP Exceptional Circumstance provision, PSP access point monitoring is a zero defect issue. <p>We recommend that the SDT review all of the requirements of CIP V5 to determine whether: a CIP Exceptional Circumstances provision should be added, the definition of CIP Exceptional Circumstances should be edited, and/or additional explanatory language should be added to the Guidelines and Technical Basis for each standard regarding CIP Exceptional Circumstances.</p>	

Issue 2: BES Cyber Asset definition – “redundancy”

The application of the redundancy clause in the BES Cyber Asset (BCA) definition is unclear because the use of different and separate technologies and methods reduce reliability risk by providing alternative data sources. For example, VoIP systems, data center phone systems, radios, and other backup communication systems are alternatives, yet could be considered redundant by auditors and therefore it is unclear whether there are limits to the application of the BCA adverse impact to these systems. Without such limitations, the BCA definition may encourage registered entities to reduce their use of backup/alternative systems to reduce their compliance burdens and risk. While redundant assets may typically have identical security risks and vulnerabilities, requiring both/all to be similarly protected, alternative systems or assets are often substantially different and have drastically dissimilar risks and vulnerabilities, which reduces overall risk to the BES.

Issue 3: VoIP as a BES Cyber Asset

CIP-002-5.1 4.2.3.2 exempts “Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters” from CIP-002-5.1; however, the Guidelines and Technical Basis for CIP-002-5.1 calls out operational directives (TOP, RC, BA) as an aspect of Inter-Entity Coordination and Communication function. As a result, some auditors are viewing VoIP as in scope for CIP-002-5.1 despite the exemption and fact that different and separate communication technologies are used for this function. If the exemption does not apply, then the BES Cyber Asset definition should also apply; however, EEI members are hearing that auditors do not agree and believe that VoIP used for operational directives are BES Cyber Assets even if the 15 minute impact does not apply due to the redundancy issue mentioned above.

We recommend that the SDT consider these issues and determine how best to address VoIP in the standard that is aligned with the risk to the bulk electric system.

Issue 4: LERC definition application to assets located external to the low impact asset

The last three asset classes in CIP-002-5.1 R1 are typically implemented across multiple instances of the first three classes (i.e., systems and facilities critical to system restoration, special protection systems, and distribution provider protection systems are typically implemented at control centers, substations, and generating resources).

The Low Impact External Routable Connectivity (LERC) definition appears to be based on single asset locations (“direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset **outside the asset** containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection.”) The phrase “outside the asset” can cause confusion in determining whether LERC exists for these classes of assets that are implemented across multiple sites.

For example, when evaluating a cranking path as an asset to determine if it has LERC, what does “outside the asset” mean? This could also allow for routable protocol based communication within the multiple substation cranking path to not be considered LERC and left unprotected if the entire cranking path is considered a single “asset containing low impact BES Cyber Systems.” It appears these last 3 asset classes are actually criteria that should affect the categorization of the single site asset class where they are implemented.

Issue 5: Custom software (scripts)

CIP-010-2 R1, Part 1.1, subpart 1.1.3 requires a baseline configuration for “any custom software installed.” The Guidelines and Technical Basis for this requirement states that “custom software installed may include scripts developed for local entity functions.” It is unclear whether all scripts must be considered custom software or whether only scripts that can have an impact on the bulk electric system within 15 minutes must be considered custom software under this requirement. A risk-based clarification should be added to this requirement to set boundaries as to what is considered custom software. For example, a script that alters the behavior or function of a BES Cyber Asset or System should be included; however, a script that simply gathers log data, and whose only impact to the BES Cyber Asset is the allocation of incidental CPU cycles, need not be included.

Issue 6: Applicability of the requirement part to Cyber Asset vs. Cyber System

Some requirements such as in the CIP-007-6 standard apply to Cyber Assets within a BES Cyber System (e.g., the R2 security patch management requirements), others apply at either the BES Cyber System level or Cyber Asset level (e.g., the R4 Part 4.1 logging requirements), and others don't specify if they apply at the system or asset level (e.g., R3 Part 3.1 method to deter, detect, or prevent malicious code). Although the applicable systems for each of these requirements is generally the same (i.e., high and medium impact BES Cyber Systems and their associated EACMS, PACS, and PCA), the difference in the requirements language applicability to Cyber Assets, BES Cyber System, or both makes what is necessary to comply with the requirements unclear.

For example, the requirements section for CIP-007-6 R3 Part 3.1 does not specify whether this requirement applies at the BES Cyber System level or Cyber Asset level, therefore it is unclear whether a responsible entity can protect a medium impact BES Cyber System through deploying an anti-virus solution at the BES Cyber System level or whether the entity must deploy the solution at each Cyber Asset to comply with the requirement part. Consistency among the requirements language would be helpful in clearing up this confusion.

Issue 7: Control Center definition

The NERC document titled "CIP V5 Issues for Standard Drafting Team Consideration" already raises issues with the Control Center definition related to Transmission Owner Control Centers; however, it does not address issues related to Generator Operators.

By definition, a Control Center is "one or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers ... 4) a Generator Operator for generation Facilities at two or more locations."

Dispersed or distributed generation facilities (e.g., wind, solar, hydro) may not have the traditional control building with a horseshoe operator control desk ("facility hosting operating personnel that monitor and control"). Does the facility have to perform all "real-time ... reliability tasks" or as few as one? Does a control room at a single wind farm, which controls a hundred turbines spread over many miles, meet the control center definition or does it become a control center only if it controls multiple wind farms? Also, if personnel maintains the Cyber Assets (e.g., patching or troubleshooting) is this considered "monitor and control" even though they are not personnel performing real-time reliability tasks. Does operating personnel mean those charged with the responsibility to monitor and control the BES or simply personnel who may be located at the generation Facility to maintain the equipment? Also, do each of the "generation Facilities at two or more locations" need to meet the Bulk Electric System definition to be within scope of the Control Center definition? CIP-002-5.1 Requirement R1, iii uses Generation resources, which could be interpreted to include all generation sources, even those that do not meet the Bulk Electric System definition.

As dispersed or distributed generation increases, clarity in language of the standard will become more important.

Issue 8: Security patches for operating Cyber Assets brought into scope under CIP V5

CIP-007-6 R2, Part 2.2 is clear concerning the ongoing evaluation of security patches as of July 1, 2016, but is unclear on what is required for the initial execution of the process ("evaluate security patches for applicability that have been released since the last evaluation") when there is no "last evaluation."

The standard does not require all Systems to be updated by July 1, 2016, but does require a baseline configuration, which includes a listing of all applied patches. The Guidelines and Technical Basis for CIP-010-2 states that "security patches applied would include all patches that have been applied on the cyber asset... CIP-010 Requirement R1, Part 1.1.5 requires entities to list all applied historical and current patches." This documentation requirement is particularly burdensome for an asset that has been in service for six years or longer as it requires entities to contact and work closely with their vendors to identify and get historical security patches. Also, documenting all historical patches, especially those that happened years ago will have little, if any impact on reliability.

Issue 9: Guidance for Secure Interactive Remote Access

In the Guidelines and Technical Basis for CIP-005-5, under Requirement R2 it states: “see Secure Remote Access Reference Document (see remote access alert).” Also, the Rationale for R2 states “Additional information is provided in Guidance for Secure Interactive Remote Access published by NERC in July 2011.” We believe these references are to the same document, which is properly titled under the Rationale and note that the 2011 NERC document was written in the context of V3 and not V5. Please evaluate the relevance of this guidance document to the most recent version (currently CIP-005-5). Also please clarify that IRA is intended to address access remotely from outside the organization (i.e., not to include accesses internally between protected networks).

Issue 10: Mistakes in Guidelines and Technical Basis

In implementing CIP V5, we’ve noticed a number of mistakes, which should be addressed, including:

- The rationale statements from the -5 standards were lost in several of the -6 versions of the standards. For example, the second sentence of the CIP-007-5 R2 rationale “The remediation plan can be updated as necessary to maintain the reliability of the BES, including an explanation of any rescheduling of the remediation actions.” was not carried forward to the -6 Guidelines and Technical Basis, even though there were no changes to the requirement between versions. We recommend reviewing the Rationales in the -6 standards and adding any that were deleted to the Guidelines and Technical Basis of the standard.
- For CIP-007-6 Part 2.2 the Guidelines and Technical Basis states: “Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.” However there are no CIP-007-6 R2 Parts have TFE provisions.
- For CIP-004-6 R4, under the Guidelines and Technical Basis, the Rationale for this requirement states: “to ensure that individuals with access to BES Cyber Systems and the physical and electronic locations where BES Cyber System Information is stored by the Responsible Entity have been properly authorized for such access. “ ‘Authorization’ should be considered to be a grant of permission by a person or persons empowered by the Responsible Entity to perform such grants **and included in the delegations referenced in CIP-003-6**” CIP V3 required designating approvers; however this requirement was not included in CIP-003-6 and therefore the emphasized text should be removed.
- For CIP-004-6 R4, the Rationale also references “quarterly reviews in Part 4.5”; however there is no Part 4.5 in CIP-004-6 R4.

Likes 0

Dislikes 0

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer

Yes

Document Name

Comment

NERC’s webpage for this SAR “Project 2016-02 Modifications to CIP Standards”, as of 4/11/2016, states the following:

“Also the scope of this work will incorporate existing and future RFIs relating to the CIP-002 through CIP-011 family of standards.”

AZPS does not believe any RFIs are addressed in the current SAR. We recommend updating the SAR to reference existing submitted RFIs as appropriate. Finally, AZPS recommends removal from the SAR of functional registrations that are no longer included in the Compliance Registry, e.g., Interchange Authority, Load-Serving Entity and Purchasing-Selling Entity.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6 - NPCC, Group Name RSC No Dominion

Answer

Yes

Document Name

Comment

Request that the SAR explicitly reference the correct title of the V5 TAG document, which we believe is "CIP V5 Issues for Standard Drafting Team Consideration," dated on September 15, 2015.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

Yes

Document Name

Comment

Distribution Provider is not checked as an affected Reliability Function.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	4-15-16 DRAFT CIP V5 Implementation Issues.pdf
Comment	
Southern supports the comments of EEI. See attached.	
Likes	0
Dislikes	0
Response	

Comments received from Ginette Lacasse, Seattle City Light

Here are our Subject Matter Expert’s (SME) comments. Non-italicized text is copied from SAR, with SME additions in RED. Additional SME comments are *in italics*.

Questions

- 1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.**

Yes:

No: X

Comments:

In several sections the language of the SAR summarizes that of the foundation V5TAG document, but in doing so conflates or glosses over important concepts. Seattle City Light would like to see clarification to the SAR in the following two sections: (added text in red to clarify)

- A) Cyber Asset and BES Cyber Asset (BCA) Definitions – as foundational definitions within the CIP V5 standards, the understanding of Cyber Asset and BCA terms impacts the scope of the applicable requirements. ‘Right-sizing’ the definitions of “Cyber Asset” and “BES Cyber Asset” balances between the administrative burden and negligible security benefit of an overly broad interpretation and the cyber security risk of too narrow an interpretation. The V5TAG recommends the following enhancements:

- Clarify the intent of “programmable” in Cyber Asset.
- Clarify and focus the definition of “BES Cyber Asset” including:
- Focusing the definition so that it does not subsume all other cyber asset types.
- Considering a lower bound to the term ‘adverse’ in “adverse impact”.
- Clarifying the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.

- B) Network and Externally Accessible Devices – V5TAG recommends improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
- The 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters.” When there is not an ESP at the location, consider clarity that the communication equipment considered out of scope is the same communication equipment that would be considered out of scope if it were between two ESPs.

2 Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Yes:

No: X

Comments:

3 Are there any other concerns with this SAR that haven’t been covered in previous questions?

Yes: X

No:

Comments:

Seattle would like to see the SAR address three additional areas:

- A) *Clarify those standards and parts where the requirement applies solely to the applicable BES Cyber System, those standards and parts where the requirement applies solely to individual BES Cyber Assets, those where the requirement applies to both BCS and BCA or to either at the option of the responsible entity, and those where the requirement applies to both BCS and BCA or to either depending on the circumstances and configuration.*
- B) *Clarify application of CIP-002-5, in particular the R1 identification of BES Cyber Systems and their association with specific types of assets (small “a”). The linkage is inconsistent: for High impact rating it is any “BCS located at and used by” a Control Center whereas for Medium*

impact rating it is any “BCS associated with any of the following,” the “following” being a mixed-bag collection of capital “F” Facilities, various systems or groups of Elements, specifically defined terms such as Control Center and Special Protection System, and undefined common-language concepts such as “generation” and “BES reactive resource.” Please also clarify the intent of “used by” and “associated with.” Does “used by” mean “essential to the operation of,” “involved in the operation of,” or something else? Does “associated with” combine the concepts of “used by and located at,” or would it be sufficient to be either “situated at the physical location of” or “used by”? The present language creates considerable confusion.

- C) Clarify the application of Intermediate System, as discussed by Salt River Project in their comments. Seattle supports Salt River’s position and analysis.

Seattle also supports the position that Florida Municipal Power Authority as they submitted in their comments.

Comments received from Kara Douglas – NRG

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Yes:

No: X

Comments:

A) Please consider the definition of Cyber Asset and clarify the intent of the term “Programmable” through consideration of whether a device is merely configurable, its executable code is not field upgradable or field Programmable, or if its functionality can only be changed via physical DIP switches, swapping internal chips, etc. (which relates to upgrading the executable in the Programmable code and the ability to field program the configuration)

B) In relation to the terms: “adverse impact” and “control center”, NRG proposes that when addressing TO and TOP Control Center functional obligations in CIP-002-5.1 Attachment 1, it also consider addressing similar issues facing Generator Owners (GO) and Generator Operators (GOP). There are GOP “control centers” that do not have traditional control capabilities over generator breakers or output but simply verbally direct generator actions. In this case it is the GOs that perform the actual output changes and breaker operation. Clarifying GO/GOP obligations in tandem with proposed TO/TOP clarification for determining impact is a step forward.

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Yes:
No: X
Comments:

3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Yes:
No: X
Comments:

Comments received from Marc Donaldson, Tacoma Power

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Yes:

No: X

Comments: Tacoma Power suggests the following scope changes:

- SDT should clarify CIP-005 R1 Part 1.5 with respect to encrypted communications, either in the G&TB or, directly within the requirement language.
- SDT could provide clarity on CIP-002 eliminating ambiguous language ("Facility" vs. "facility" & "location") etc.
- SDT should clarify whether CIP Exceptional Circumstance exception applies to CIP-004 R3 (PRA). Within the Guidelines and Technical Basis, there is this clarifier "except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response." We suggest the SDT include an exception for CIP Exceptional Circumstance specifically within the requirement language.

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Yes:

No: X

Comments:

3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Yes:

No: X

Comments:

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard(s):	Modifications to CIP Standards		
Date Submitted:	June 1, 2016		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC		
Telephone:	609-651-9455	E-mail:	Stephen.Crutchfield@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):

The purpose of this project is to (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the *CIP V5 Issues for Standard Drafting Team Consideration* (V5TAG Transfer Document) and (2) address the Federal Energy Regulatory Commission (Commission) directives contained in Order 822. These revisions will increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities.

Industry Need (What is the industry problem this request is trying to solve?):

The V5TAG, which consists of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing standard drafting team (SDT) for the CIP Reliability Standards.

SAR Information

The V5TAG developed the V5TAG Transfer Document to explain the issues and recommend that the SDT consider them in future development activity.

On January 21, 2016, the Commission issued Order No. 822 approving revisions to the CIP version 5 standards and also directing NERC to develop modifications to address:

- Protection of transient electronic devices used at low-impact BES Cyber Systems;
- Protections for communication network components between control centers; and
- Refinement of the Low Impact External Routable Connectivity (LERC) definition.

The Commission did not provide a date by which the modifications for transient devices or communication networks must be completed. For the LERC definition, however, the Commission directed that NERC submit the modification within one year of the effective date of Order No. 822 (March 31, 2017).

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The proposed project will consider the issues raised by the V5TAG in the V5TAG Transfer Document and will address the Commission directives in Order No. 822 through modifications to the CIP standards. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards and will meet the deadlines established by the Commission in Order No. 822.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

As stated above, the purpose of this project is to consider the V5TAG issues in the initial transfer document V5TAG Transfer Document and address the Commission directives contained in Order 822. For the directive on the LERC definition, the project is to respond within the deadline required in the order.

As noted above, the V5TAG identified specific issues with the CIP V5 standards. The V5TAG drafted the V5TAG Transfer Document to formally recommend that the SDT address these issues during standards development to consider whether modifications can be made to the standard language. As outlined in the V5TAG Transfer Document, the specific issues are as follows:

- Cyber Asset and BES Cyber Asset (BCA) Definitions – as foundational definitions within the CIP V5 standards, the understanding of Cyber Asset and BCA terms impacts the scope of the applicable requirements. The V5TAG recommends the following enhancements:
 - Clarify the intent of “programmable” in Cyber Asset.
 - Clarify and focus the definition of “BES Cyber Asset” including:
 - Focusing the definition so that it does not subsume all other cyber asset types.
 - Considering a lower bound to the term ‘adverse’ in “adverse impact”.

SAR Information

- Clarifying the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
- Network and Externally Accessible Devices – V5TAG recommends improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
 - The 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters”
 - The meaning of the word ‘associated’ in the ERC definition.
 - The applicability of ERC including the concept of the term “directly” used in the phrase “cannot be directly accessed through External Routable Connectivity” within the Applicability section.
 - The IRA definition placement of the phrase “using a routable protocol” in the definition and with respect to Dial-up Connectivity.
 - The Guidelines and Technical Basis sentence, “If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.”
- Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations – V5TAG is aware of multiple interpretations of the language “used to perform the functional obligation of” in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
 - The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
 - The definition of Control Center.
 - The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.
- Virtualization – The CIP V5 standards do not specifically address virtualization. Because of the increasing use of virtualization in industrial control system environments, V5TAG asked that the SDT consider the CIP V5 standards and the associated definitions regarding permitted architecture and the security risks of virtualization technologies.

The SDT shall also address the Order No. 822 directives by developing modifications to requirements in CIP standards and the definition of LERC. The Commission directed the following:

- *Per paragraph 32, “...we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission’s concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.”*

SAR Information

- *Per paragraph 53, “...the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).”*
- *Per paragraph 73, “...the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term “direct” as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule....”*

In addition, the SDT will review and address the CIP V5 requirements for CIP Exceptional Circumstances exceptions.

Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input checked="" type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.

Reliability Functions	
<input checked="" type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input checked="" type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/> Transmission Owner	Owens and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input checked="" type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/> Generator Owner	Owens and maintains generation facilities.
<input checked="" type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply).

<input type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input checked="" type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards

Standard No.	Explanation

Related Standards	

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

Standards Authorization Request Form

When completed, email this form to:

sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard(s):	Modifications to CIP Standards		
Date Submitted:	March 9 <u>June 1</u> , 2016		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC		
Telephone:	609-651-9455	E-mail:	Stephen.Crutchfield@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):

The purpose of this project is to (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the *CIP V5 Issues for Standard Drafting Team Consideration* (V5TAG Transfer Document) and (2) address the Federal Energy Regulatory Commission (Commission) directives contained in Order 822. These revisions will increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities.

Industry Need (What is the industry problem this request is trying to solve?):

The V5TAG, which consists of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP ~~version~~ **V5** standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing standard drafting team (SDT) for the CIP Reliability Standards.

SAR Information

The V5-TAG developed the V5TAG Transfer Document to explain the issues and recommend that the SDT consider them in future development activity.

On January 21, 2016, the Commission issued Order No. 822 approving revisions to the CIP version 5 standards and also directing NERC to develop modifications to address:

- Protection of transient electronic devices used at low-impact BES Cyber Systems;
- Protections for communication network components between control centers; and
- Refinement of the Low Impact External Routable Connectivity (LERC) definition.

The Commission did not provide a date by which the modifications for transient devices or communication networks must be completed. For the LERC definition, however, the Commission directed that NERC submit the modification within one year of the effective date of Order No. 822 (March 31, 2017).

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The proposed project will consider the issues raised by the V5TAG in the V5TAG Transfer Document and will address the Commission directives in Order No. 822 through modifications to the CIP standards. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards and will meet the deadlines established by the Commission in Order No. 822.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

As stated above, the purpose of this project is to consider the V5TAG issues in the initial transfer document V5TAG Transfer Document and address the Commission directives contained in Order 822. For the directive on the LERC definition, the project is to respond within the deadline required in the order.

As noted above, the V5TAG identified specific issues with the CIP V5 standards. The V5TAG drafted the V5TAG Transfer Document to formally recommend that the SDT address these issues during standards development to consider whether modifications can be made to the standard language. As outlined in the V5TAG Transfer Document, the specific issues are as follows:

- Cyber Asset and BES Cyber Asset (BCA) Definitions – as foundational definitions within the CIP V5 standards, the understanding of Cyber Asset and BCA terms impacts the scope of the applicable requirements. The V5TAG recommends the following enhancements:
 - Clarify the intent of “programmable” in Cyber Asset.
 - Clarify and focus the definition of “BES Cyber Asset” including:

SAR Information

- Focusing the definition so that it does not subsume all other cyber asset types.
 - Considering a lower bound to the term ‘adverse’ in “adverse impact”.
 - Clarifying the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
- Network and Externally Accessible Devices – V5TAG recommends improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
 - The 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters”
 - The meaning of the word ‘associated’ in the ERC definition.
 - The applicability of ERC including the concept of the term “directly” used in the phrase “cannot be directly accessed through External Routable Connectivity” within the Applicability section.
 - The IRA definition placement of the phrase “using a routable protocol” in the definition and with respect to Dial-up Connectivity.
 - The Guidelines and Technical Basis sentence, “If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.”
- Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations – V5TAG is aware of multiple interpretations of the language “used to perform the functional obligation of” in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
 - The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
 - The definition of Control Center.
 - The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.
- Virtualization – The CIP V5 standards do not specifically address virtualization. Because of the increasing use of virtualization in industrial control system environments, V5TAG asked that the SDT consider the CIP-005 V5 standards and the associated definitions of Cyber Asset and Electronic Access Point regarding permitted architecture and the security risks of network, server and storage virtualization technologies.

The SDT shall also address the Order No. 822 directives by developing modifications to requirements in CIP standards and the definition of LERC. The Commission directed the following:

- *Per paragraph 32, “...we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission’s concerns, the proposed modifications should be designed to effectively address the risks posed by*

SAR Information

transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.”

- *Per paragraph 53, “...the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).”*
- *Per paragraph 73, “...the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term “direct” as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule....”*

In addition, the SDT will review and address the CIP V5 requirements for CIP Exceptional Circumstances exceptions.

Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input checked="" type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.

Reliability Functions	
<input checked="" type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input checked="" type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input checked="" type="checkbox"/> Transmission Service <input type="checkbox"/> Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input checked="" type="checkbox"/> Transmission Owner	Owens and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> <input checked="" type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/> Generator Owner	Owens and maintains generation facilities.
<input checked="" type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply).

<input type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
<input type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input checked="" type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards

Standard No.	Explanation

Related Standards	

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards Standards Authorization Request (SAR)

Do not use this form for submitting comments. Use the [electronic form](#) to submit comments on the **Project 2016-02 Modifications to CIP Standards SAR**. The electronic comment form must be submitted by **8 p.m. Eastern, Thursday, June 30, 2016**.

Additional information about this project is available on the [Project 2016-02 Modifications to CIP Standards](#) page. If you have questions, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

Background Information

On January 21, 2016, the Commission issued [Order No. 822](#), *Revised Critical Infrastructure Protection Reliability Standards*, approving seven CIP Reliability Standards and new or modified definitions. On March 9, 2016, the NERC Standards Committee accepted the Standards Authorization Request (SAR) and authorized the posting of the Modifications to CIP Standards SAR. It was posted for a 30-day informal comment period March 23 – April 21, 2016. Based on the comments received, the Standard Drafting Team (SDT) made minor revisions to the SAR which will be posted for an additional 30-day informal comment period.

It was noted in the comments received on the SAR that the Virtualization issue involved more than just CIP-005 standards and the defined terms Cyber Asset and Electronic Access Point. To correct this, the SDT revised the sentence to: “Because of the increasing use of virtualization in industrial control system environments, V5TAG asked that the SDT consider ~~CIP-005 and the definitions of Cyber Asset and Electronic Access Point~~ the CIP V5 standards and the associated definitions regarding permitted architecture and the security risks of ~~network, server and storage~~ virtualization technologies.”

Other commenters suggested that the SDT include provisions to address CIP Exceptional Circumstances. A sentence was added to the SAR to include this topic: “In addition, the SDT will review and address the CIP V5 requirements for CIP Exceptional Circumstances exceptions.”

A sentence was also added to the SAR allowing the SDT to make errata changes to the standards as necessary and to correct grammatical, punctuation and/or formatting errors in the V5 Standards: “Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary.”

In the previous version of the SAR, the Transmission Service Provide (TSP) Reliability Function was checked as an applicable function. The TSP is not applicable under the CIP standards and this function was corrected by unchecking the TSP Reliability Function in this version of the SAR. Similarly, the Distribution

Provider (DP) Reliability Function was left unchecked in the original SAR. The CIP Standards apply to the DP, so this was corrected by checking the DP Reliability Function in this version of the SAR.

Questions

1. The CIP SDT revised the SAR based on the comments received in the previous posting as noted above. Do you agree with these revisions to the SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Yes:

No:

Comments:

CIP V5 Issues for Standard Drafting Team Consideration

September 15, 2015

From experience in the V5 Transition Study and the on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty in implementation of the requirements. In many cases, the V5TAG members found that select language within the CIP Version 5 standards may be understood in multiple ways. These interpretations appear to go beyond the intended flexibility of the standard language that is necessary to accommodate the diverse nature of facts and circumstances across the electric sector. At this time, the V5TAG proposes the following issues to be addressed by the CIP V5 Revisions drafting team (SDT) or other appropriate team for standards development:

- **Cyber Asset and BES Cyber Asset definitions**

The foundational definition for the CIP Version 5 standards is ‘Cyber Assets.’ When Cyber Assets meet a threshold of Bulk Electric System (BES) impact they become ‘BES Cyber Assets (BCA)’ which are grouped, by a Responsible Entity, into ‘BES Cyber Systems (BCS).’ Viewing BCAs too broadly can lead to many thousands of devices in the typical utility becoming an administrative burden for which few if any cyber security controls can actually be applied or where there is limited associated cyber security risk. Vast amounts of effort would be expended for these types of cyber assets to track and document their lack of capability for even the most basic cyber security controls. Viewing BCAs too narrowly could lead to missing consideration of devices that have a sufficient level of cyber capability and risk impact.

The SDT should consider the definition of Cyber Asset and clarify the intent of “programmable” by considering such factors as if a device is merely configurable, its executable code is not field upgradable, or if its functionality can only be changed via physical DIP switches, swapping internal chips, etc.

The SDT should consider clarifying and focusing the definition of “BES Cyber Asset” including:

- a. Focusing the definition so that it does not subsume all other cyber asset types. Protected Cyber Assets (PCA), by nature of being on the same network, can have some form of adverse impact if misused. Electronic Access Control or Monitoring Systems (EACMS) if misused or unavailable can have some form of adverse impact. This can result in a “hall of

mirrors” effect where everything in or that creates an Electronic Security Perimeter (ESP) also meets the BCA definition.

- b. Considering if there is a lower bound to the term ‘adverse’ in “adverse impact”. For example, is the focus of a typical generating unit the servers and operator human machine interfaces (HMI) and controller cabinets and Programmable Logic Controllers (PLCs) or is it the thousands of individual sensors and transmitters throughout the plant?
 - c. Clarify the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that “N-1 contingency” is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
- **Network and Externally Accessible Devices (ERC, ESP, IRA)**
The SDT should consider the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
 - a. Clarify the 4.2.3.2 exemption phrase “between discrete Electronic Security Perimeters.” When there is not an ESP at the location, consider clarity that the communication equipment considered out of scope is the same communication equipment that would be considered out of scope if it were between two ESPs.
 - b. The word ‘associated’ in the ERC definition is unclear in that it alludes to some form of relationship but does not define the relationship between the items. Striking ‘associated’ and defining the intended relationship would provide much needed clarity.
 - c. Review of the applicability of ERC including the concept of the term “directly” used in the phrase “cannot be directly accessed through External Routable Connectivity” within the Applicability section. As well, consider the interplay between IRA and ERC.
 - d. Clarify the IRA definition to address the placement of the phrase “using a routable protocol” in the definition and clarity with respect to Dial-up Connectivity.
 - e. Address the Guidelines and Technical Basis sentence, “If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.”
 - **Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations**
CIP-002-5.1 Attachment 1 – Impact Reliability Criteria, sections 1.1, 1.2, 1.3, 1.4, 2.11, 2.12, and 2.13 employ the language “used to perform the functional obligation of”, and then lists the functional registration. It was intended that this caveat would capture entities that perform obligations of a specific registered function, whether they are registered for that function or not. However, this language has caused confusion, especially in section 2.12 concerning TOP Control Centers. The term “functional obligation” may be interpreted to have different meaning in a variety of situations.

One interpretation is for the defined term Control Center to be strictly associated with the Balancing Authority (BA), Generator Operator (GOP), Reliability Coordinator (RC), and Transmission Operator (TOP) functional registrations, and that control rooms or dispatch centers owned and operated by Transmission Owners (TOs) with control of limited BES facilities would be excluded. A second interpretation may expand or contract the applicability of the Control Center designation, based on criteria that may not take into consideration overall risk to reliable operations of the BES.

Early analysis found the potential for TOs (not Registered as TOPs) that only operate limited breakers to be pulled in as medium impact Control Centers, even if the few Facilities they control are low impact. (For example, an entity with one 161kV breaker in one substation and a second 161kV breaker in a different substation, both breakers associated with low impact Facilities.) As currently written, low impact Control Centers are to be identified per criteria 3.1 and could be commensurate with risk for these scenarios.

Areas for the SDT to address are:

- a. CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.
 - b. Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the “CIP-002-5” section paragraph starting with “Responsibility for the reliable operation of the BES is spread across all Entity Registrations”; the table following that paragraph; the “High Impact Rating (H)” section; and the criterion bullets for Control Centers under the “Medium Impact Rating (M)” section.
 - c. The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include ‘Control Center’, for example, the revised Glossary term for “System Operator” to be effective July 1, 2016).
 - d. The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.
- **Virtualization**

The CIP Version 5 standards do not specifically address virtualization. However, because of the increasing use of virtualization in industrial control system environments, questions around treatment of virtualization within the CIP Standards are due for consideration.

The SDT should consider revisions to CIP-005 and the definitions of Cyber Asset and Electronic Access Point that make clear the permitted architecture and address the security risks of network, server and storage virtualization technologies.

The transition to CIP Version 5 continues as the compliance deadline of April 1, 2016 approaches. The V5TAG continues to discuss challenging issues being undertaken during the on-going implementation. The group may find additional issues to transfer to the SDT for consideration.

Standards Announcement

Project 2016-02 Modifications to CIP Standards Standards Authorization Request

Informal Comment Period Open through June 30, 2016

[Now Available](#)

A 30-day informal comment period for the **Project 2016-02 Standards Authorization Request (SAR)**, is open through **8 p.m. Eastern, Thursday, June 30, 2016**.

Commenting

Use the [electronic form](#) to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project

For more information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact either Senior Standards Developer, [Stephen Crutchfield](#) at (609) 651-9455 or [Al McMeekin](#) at (404) 446-9675.

North American Electric Reliability Corporation

3353 Peachtree Rd, NE

Suite 600, North Tower

Atlanta, GA 30326

404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards SAR June 2016
Comment Period Start Date: 6/1/2016
Comment Period End Date: 6/30/2016
Associated Ballots:

There were 21 sets of responses, including comments from approximately 21 different people from approximately 21 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. The CIP SDT revised the SAR based on the comments received in the previous posting as noted above. Do you agree with these revisions to the SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hills	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO

					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
BC Hydro and Power Authority	Patricia Robertson	1,2,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC
					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC					

					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con-Edison	1	NPCC
					Kelly Silver	Con-Edison	3	NPCC
					Peter Yost	Con-Edison	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Brian O'Boyle	Con-Edison	5	NPCC
					Kathleen M. Goodman	ISO-NE	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
Colorado Springs Utilities	Shannon Fair	1,3,5,6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE

					Kim VanBrimer	Southwest Power Pool Inc	2	SPP RE
					John Allen	City Utilities of Springfield	1,4	SPP RE
					Mike Buyce	City Utilities of Springfield	1,4	SPP RE
					Paul Mehlhaff	Sunflower Electric Power Corporation	1	SPP RE
					TARA Lightner	Sunflower Electric Power Corporation	1	SPP RE
ACES Power Marketing	Warren Cross	1,3,4,5	MRO,RF,SERC,SPP RE,Texas RE,WECC	ACES Standards Collaborators	Brazos Electric Power Cooperative, Inc.	BREC	1,5	Texas RE
					Western Farmers Electric Cooperative	WFEC	1,5	SPP RE
					Old Dominion Electric Cooperative	ODEC	3,4	SERC
					Golden Spread Electric Cooperative	GSEC	5	SPP RE
					Prairie Power, Inc.	PPI	1,3	SERC
					Arizona Electric Power Cooperative, Inc.	AEPC	1	WECC
					Hoosier Energy Rural Electric Cooperative, Inc.	HE	1	RF

1. The CIP SDT revised the SAR based on the comments received in the previous posting as noted above. Do you agree with these revisions to the SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Bob Reynolds - 10

Answer No

Document Name

Comment

The SPP RE respectfully submits the following two comments to the Project 2016-02 Standards Authorization Request: (1) Reference the comments submitted by the SPP Regional Entity (SPP RE) April 2016. In those comments, the SPP RE pointed out that Tie Line and other Transmission line flow meters appear to have been unintentionally excluded from consideration under CIP-002-5.1, Impact Rating Criterion 2.5. This significant issue does not appear to have been included in the revised SAR. The original SPP RE comment is restated here: "Impact Rating Criterion 2.5 excludes consideration of BES Cyber Assets associated with Transmission lines through its use of "operating between 200 kV and 499 kV at a single station or substation" language. In the instance where the tie line or other flow meter is associated with a Transmission Line operated between 200 and 499 KV in a substation that satisfies the qualifications of Impact Rating Criterion 2.5, the meter will be excluded and not be categorized as Medium Impacting. Additionally, some entities are proffering the argument that the flow meter is not a BES Cyber Asset because its loss or misuse will not affect the reliable operation of the Transmission Facilities in the substation where the meter resides, overlooking the impact the loss of meter information may have on Control Center operations including ACE calculation, security-constrained generation dispatch, AGC, and Situational Awareness. An additional Criterion, specific to Transmission line flow meters, may be required to address this issue." (2) The SPP RE notes that the revised SAR still makes no mention of the consideration of submitted and outstanding Requests for Interpretation. NERC staff has stated publicly that the RFIs would be addressed by the Standards Drafting Team. The SPP RE is aware that at least one of the issues discussed in the April 2016 comments to the SAR has been formally submitted as a Request for Interpretation. To fail to consider outstanding RFIs in the course of modifying the CIP Standards under this SAR would be a missed opportunity to address significant confusion regarding the expectations of the Requirements under question.

Likes 0

Dislikes 0

Response

Mike Smith - 1,3,5,6

Answer No

Document Name

Comment

For virtualization, Manitoba Hydro does not agree with NERC prescribing specific system architecture, technologies or designs. SDT should continue to focus on identifying requirements to meet specific objectives for the virtualization.

Manitoba Hydro agrees with adding more CIP V5 requirements exceptions for CIP Exceptional Circumstance.

Likes 0

Dislikes 0

Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
<p>The NSRF agrees with the drafting team's addition of "reviewing and addressing the CIP V5 requirements for CIP Exceptional Circumstances exceptions" to the SAR. However, we request clarification on the scope of Guidelines and Technical Basis sections that may be changed with updates to the associated Standards within this project. We believe that addressing all CIP V5 Guidelines and Technical Basis sections within the scope of this revision may make the project unwieldy as it already contains a substantial scope of work to address FERC directives. We suggest that only Guidelines and Technical Basis sections related to standards language updates should be addressed within the scope of this project.</p>	
Likes	0
Dislikes	0
Response	
Patricia Robertson - 1,2,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
<p>CIP-002-5.1</p> <p>A) The topic of adverse impact should provide more clarity on the real-time requirement as well.</p> <p>B) Per Medium Impact criterion 2.3 for generation resources, need further clarity on the extent of planning horizon > 1 year contingencies to consider regarding the determination of BES Adverse Reliability Impacts to a given Interconnection. The Guidelines and Technical basis of CIP-002-5.1 reference as an example, TPL-003 Category C3 contingency system studies but otherwise, there is no lower or upper limit indicated regarding the depth of contingencies to be considered. The limit is currently subjective for Transmission Planners and Planning Coordinators.</p> <p>Furthermore, per the definition of Adverse Reliability Impact, there is direct reference to impacts on a given Interconnection but it is not clear whether this is only considering inter-tie paths or general BES impacts beyond a specific BES location (i.e. generation plant or substation). The Guidelines and Technical basis state only widespread impacts are to be considered instead of localized impacts but it is not clear what is considered 'widespread'.</p> <p>CIP-005-5 The fundamental concepts of the intermediate system are omitted or subjective. The standards should define what the requirements are for this system, whether it is strictly a jump host (not mentioned in the standards) or can have more functionality (i.e. software installed upon it). This should be included in the 'Network and Externally Accessible Devices' section.</p> <p>CIP-005-5/CIP-003-6 A clear exemption is given for low impact systems is given in CIP-003-6 Guidelines and Technical Basis (CIP-006-6 pg 28) "To future-proof the standards, and in order to avoid future technology issues, the definitions specifically exclude "point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems," such as IEC 61850 messaging." The 'Network and Externally Accessible Device'"</p>	

section should address this topic for medium impact BCS/BCA as well. These technologies are not limited to low impact systems and guidance should be provided.

CIP-007-5: Regarding security patch applications and cyber vulnerability assessments:

- Certain legacy devices (i.e. HMIs, PLCs, etc.) can be in a “fragile” state and are at high-risk regarding the application of software updates, which include cyber security related updates. There is a demonstrable risk in breaking their functionality which can have an adverse impact on the BES as the only solution is to replace the device entirely or at best, perform a complete reset of the device. This is mainly due to bugs that could be introduced by vendors through their patches (not enough regression testing done by the vendors) and for which even testing prior to implementation in a production environment may not identify all such bugs prior to implementation. Recommend providing guidance around how to handle the application of cyber security patches to these “fragile” devices and to potentially not mandate security patch applications in all cases where there may be demonstrable evidence of adverse BES impact.
- Further guidance is required within the Guidelines and Technical basis on the exact difference between a ‘paper’ exercise cyber vulnerability assessments (CVA) and ‘active’ CVA with respect to Medium Impact facilities and the extent an entity is expected to go to achieve this. It has been communicated by Regional Entities’ audit approach that paper scans must incorporate some active component to pull configuration settings, etc. from a device for analysis. For legacy devices (namely firmware devices), these active component scans can also pose a risk in breaking the functionality of said devices, which can cause adverse impact to the BES. Recommend including guidance around how to handle CVAs pertaining to these firmware devices without potentially breaking their functionality.

Likes 0

Dislikes 0

Response

Chris Mattson - 1,3,4,5,6

Answer

No

Document Name

Comment

Tacoma asks that the SDT consider removing the final two sentences from the last paragraph of CIP-005-5, Guidelines and Technical Basis, Section 4 – Scope and Applicability of the CIP Cyber Security Standards, Requirement R1. These are shown in bold below for identification:

*The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. **Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.***

Tacoma is asking the SDT to consider that there are other methods and technologies for detecting malicious traffic in addition to deep packet inspection. This change to the G&TB would make the standard more consistent with the language in FERC Order No. 706, Paragraph 501 which indicates that it is not the commission’s intent to mandate any specific mechanism to be the second security measure. The language from the FERC order is shown below for reference and the pertinent language is shown in bold:

Paragraph 501. In response to SDG&E and Entergy, in stating that the placement of security measures in front of systems provides a layer of protection for those systems, the Commission was not giving priority to “in front” measures. In fact, the Commission acknowledged in the CIP NOPR that defense

*in depth measures are generally integrated within and constitute part of a system or program. In commenting that defense in depth measures may also be effectively placed in front of a system, the Commission intended only to acknowledge that there are multiple ways to implement a defense in depth strategy. **The Commission is not mandating any specific mechanism to be the second security measure. We are also not requiring uniformity of security measures, only that each responsible entity have at least two security measures unless it is not technically feasible to do so.** The revised CIP Reliability Standard should allow enough flexibility for a responsible entity to take into account each site's specific environment. The Commission believes that this, in conjunction with the allowance of technical feasibility exceptions, alleviates FPL Group's concern that the Commission's proposal is a "one size fits all" approach.*

Also, the SDT should clarify CIP-005 R1 Part 1.5 with respect to encrypted communications either in the G&TB or directly within the requirement language. It important that the SDT clarify how to detect malicious communications when the communications includes encrypted information that is not readily decrypted to allow inspection.

Likes 0

Dislikes 0

Response

Maryclaire Yatsko - 1,3,4,5,6 - FRCC

Answer

No

Document Name

Comment

Although Seminole concurs with all items currently listed in the draft Standards Authorization Request, Seminole recommends that additional items should be included in the SAR. Seminole thanks the SAR team for addressing our previous comments, in addition to those of others, related to Exceptional Circumstances and the Guidelines and Technical Basis.

While the changes addressed are necessary to address mandatory requirements from FERC, this SAR does not address the fundamental deficiencies in the current CIP standards. Until these fundamental issues are addressed, the electric sector will continue to struggle implementing the current standard, be faced with inefficiencies in the standard that do not improve cyber and physical security, and have difficulty using new and improved capabilities in a rapidly evolving marketplace.

Seminole recommends adding the following items to the SAR:

1. Update CIP-002 Requirements and the Guidelines and Technical Basis section to clarify the expectations in complying with this standard. Update evidence requirements to make clear the expectations of the standard. Clarify attachment 1 to address V5TAG Lessons Learned and FAQs. Resolve issues in the Guidelines and Technical Basis that are inconsistent with the definition of BES Cyber Asset and BES Cyber System.

2. The SDT will review applicable Standards and Requirements to clarify the SDT's intent for management of shared Facilities when more than one Registered Entity owns Facilities inside a single asset. Interconnections within the BES and with Distribution Providers within a single asset create significant complexity for entities in some regions. This results in a need for a significant number of MOU, CFR, or JRO that both complicates compliance and the audit process.

3. The SDT will review the Measures in the CIP V5 standards and adjust where appropriate to allow an entity that provides evidence consistent with the identified measures to determine compliance if no deficiencies are identified in the provided evidence. This may include modifying measures to match the CIP Version 5 Evidence Request or by clarifying either the measures or Guidelines and Technical basis to clarify intent for adjustment of the evidence request.

Likes 0

Dislikes 0

Response

Julie Hall - 6

Answer

No

Document Name

Comment

Comments: Entergy requests that more detail be provided regarding the actions that will be considered regarding CIP Exceptional Circumstances. Is more specificity regarding what constitutes a CIP Exceptional Circumstance being considered? Is more specificity regarding how to declare and document a CIP Exceptional Circumstance being considered? Will more clarity regarding standards affected by CIP Exceptional Circumstance, including a possible increase of applicable standards, be considered? Some particular questions Entergy has regarding the scope of standards affected by CIP Exceptional Circumstances include:

- CIP-004-5.1 R3 does not include the “except during CIP Exceptional Circumstances” language, yet the Guidelines and Technical Basis section states “Each Responsible Entity shall ensure a personnel risk assessment is performed for all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, prior to their being granted authorized access, except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response.” The language in the Guidelines and Technical Basis seems logical as it may not be feasible to validate PRA’s during a widespread emergency response (i.e. a hurricane) especially when response support is provided by many other companies and/or vendors across the country. It is requested that the “except during CIP Exceptional Circumstances” language be added to the appropriate parts of CIP-004-5.1 R3, particularly CIP-004-5.1 R3 Part 3.5.
- The “except during CIP Exceptional Circumstances” language exists in CIP-006-5 R2 Part 2.1 and Part 2.2 which states that logging and continuous escorting of visitors is not required during CIP Exceptional Circumstances. However, none of the CIP-006-5 R1 parts include the “except during CIP Exceptional Circumstances” language, which in turn requires alerting, monitoring, logging of access approved individuals. This may not be feasible during a widespread event that results in total loss of power at many sites over a widespread geographical area. It is requested that the “except during CIP Exceptional Circumstances” language be added to the appropriate parts of CIP-006-5, particularly R1 to ensure consistency across CIP-006-5.

Likes 0

Dislikes 0

Response

Scott Brame - 3,4,5 - SERC

Answer No

Document Name

Comment

The following comments are from my CIP SME.

• Per paragraph 73, "...the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d) (5) of the FPA, we direct NERC to develop a modification.

This is where I believe FERC's order falls short. Although, the definition for LERC needs to be improved and needs to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6. In my opinion, the requirements for low impact critical assets is incomplete. It appears like the SDT was rushed to provide requirements for low impact. Although, the SDT included some basic requirements for low impact critical assets they should have also included requirements for malware and virus protections. In addition, there should be requirements for logging and auditing of systems and system access. These requirements do not need to be as stringent and comprehensive as what is required for medium and high impact critical assets, but they should also be required for low impact critical assets.

Likes 0

Dislikes 0

Response

Warren Cross - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer No

Document Name

Comment

Thank you for the opportunity to provide comments regarding the Standards Authorization Request (SAR) in response to FERC Directives and v5TAG recommendations. While the current SAR attempts to resolve issues around LERC, virtualization and communication protections, ACES believes the SAR doesn't adequately detail the areas of concern for LERC and fails to allow for technology advances, which may ultimately hinder industry adoption of more secure solutions to address cyber security threats.

How LERC will be defined based upon the ability to communicate and interactive communication capabilities between Low Impact Facilities that have BES Cyber Assets associated with them has yet to be fully vetted. The ability to communicate with a BES Cyber Asset isn't the same as interacting with the BES Cyber Asset. This distinction needs to be clearly defined. Another issue for Low Impact BES Cyber Systems is the need for a common definition of when serial devices are in scope and not in scope for consistent industry implementation.

Host-based security applications, advanced security threat analysis services, and cloud-based networks are not in scope for the SAR. There are mechanisms in place in the CIP standards that allow for exceptions, such as TFEs and CIP Exceptional Circumstances. ACES believes that these definitions could be expanded to include technology that exists outside of the standard to be able to be used, with approval, in order to provide the entity with a stronger defense in depth security profile.

If the drafting team proposes to modify definitions, they should consider a process that is non-prescriptive and provides flexibility for registered entities to decide how to best defend against cyber security threats based on their risk analysis. There may be significant advantages for industry to adopt new emerging security applications and cloud based security services. The CIP standards should not limit the tools or technology available to mitigate cyber security risks. We ask the drafting team to consider how the revisions to the CIP standards would allow for the power industry to match the security best practices of other industries against the latest security threats and vulnerabilities.

Thank you for your time and attention regarding this SAR.

Likes 0

Dislikes 0

Response

Erika Doot - 1,5

Answer

No

Document Name

Comment

The Bureau of Reclamation agrees with the drafting team's addition of "reviewing and addressing the CIP V5 requirements for CIP Exceptional Circumstances exceptions" to the SAR. However, Reclamation requests clarification on the scope of Guidelines and Technical Basis sections that may be changed with updates to the associated Standards within this project. Reclamation believes that addressing all CIP V5 Guidelines and Technical Basis sections within the scope of this revision may make the project unwieldy as it already contains a substantial scope of work to address FERC directives. Reclamation suggests that only Guidelines and Technical Basis sections related to standards language updates should be addressed within the scope of this project.

Likes 0

Dislikes 0

Response

Shannon Fair - 1,3,5,6, Group Name Colorado Springs Utilities

Answer

Yes

Document Name

Comment

CSU supports the standard drafting teams updates to the SAR.

Likes 0

Dislikes 0

Response

Thomas Foltz - 3,5

Answer

Yes

Document Name

Comment

AEP suggests that the SDT include separate balloting and commenting for Guidelines and Technical Basis throughout this project. With the development of implementation guidance, AEP is unsure whether the Guidelines and Technical Basis document should remain a part of the codified Reliability Standard. If it does, then stakeholders should have the ability to vote and comment on the contents specifically.

Likes 0

Dislikes 0

Response

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

As our review group evaluated the revised SAR, we noticed that the V5TAG recommends providing clarity in the definitions of the two terms 'External Routable Connectivity (ERC)' and 'Interactive Remote Access (IRA). We suggest the drafting team either develop a new SAR or modify this one in order to require the term 'External Routable Connectivity (ERC)' to have the acronym and revised definition updated in the NERC Glossary and also included in the Rules of Procedure (RoP) for consistency and proper alignment. Additionally, we suggest the drafting team edit the SAR to review the Rules of Procedure where the acronym (IRA), is used to refer to 'Inherent Risk Assessment' whereas the CIP Standards refer to a term 'Interactive Remote Access' but do not use an acronym. There could be confusion if an acronym is used in either document for either of these terms. We suggest not using an acronym for either term in any document.

We also request clarification on why there is a specific deadline for updating the definition of LERC.

As for the term 'Low Impact External Routable Connectivity-LERC', we suggest the drafting team edit the SAR to clarify that a revised definition will also be included in the RoP.

When clarifying the 'lower bound' clarification in "adverse impact", we would appreciate a clear example (beyond the one used in the V5TAG document) that explains this concept.

We also request the SDT review or consider creating definitions or otherwise providing clarity for 'custom software' and the use of 'scripts'. There are several instances of regional inconsistencies in the scope of 'scripts' that should be included in an entity's baseline. Direction or clarity from this drafting team would be appreciated. Additional requirements or definitions may not be required, but guidance, rationale, or technical background would be beneficial.

Likes 0

Dislikes 0

Response

Stephanie Little - 1,3,5,6

Answer

Yes

Document Name

Comment

Arizona Public Service (AZPS) appreciates the opportunity to comment on the revised SAR, and submits the following comments previously provided in response to the initial SAR. Although AZPS generally supports the scope as described in the SAR, we believe that there are additional clarifications that should be considered beyond those detailed in the FERC Order 822 and the CIP Version 5 Transition Advisory Group (V5TAG) considerations.

AZPS believes the industry would benefit from clarification of the definition of the following terms:

- Transmission Facility – Transmission Facility is not a defined term. Although Facility is a defined term, AZPS does not believe that the Facility definition aligns with the standard's intent. AZPS suggests that a definition be provided by the Standard Drafting Team (SDT).
- Programmable - The SDT should consider defining programmable to clarify that a device would not be included simply because it was configurable, e.g., has functionality that can be changed locally.

AZPS would also like to suggest that the SDT clarify the intent of the grouping BCAs into BCS by leveraging the logically based perimeter security controls at the Electronic Security Perimeter (ESP) as well as local, device specific security controls per each BES Cyber Asset's (BCA) capability.

AZPS would also like to add some additional comments to the discussion in the V5TAG CIP V5 Issues for Standard Drafting Team Consideration document.

- AZPS recommends that the SDT consider not defining "adverse impact" or defining a lower bound thereof within the definition of BES Cyber Asset, but to revise the body of CIP standards and/or applicable defined terms to utilize already defined terms such as "Adverse Reliability Impact." Such would facilitate consistency as well as clarity regarding the N-1 contingency issue and other issues regarding that term identified by the V5TAG.
- AZPS believes that when BES Cyber Assets (BCA), such as relays, RTUs, and others, are connected via serial links to IP converters and/or IP-enabled security gateways, it would be appropriate to consider those elements downstream of the security gateways as BCA that do not have External Routable Connectivity (ERC). This is appropriate because the IP- converters and/or IP-enable security gateways require authentication and provide a protocol break. AZPS believes accurate and timely guidance related to serially connected devices supports the overall goal of providing appropriate and effective cyber security controls; thus, improving reliability.

- AZPS supports the CIP V5TAG analysis regarding virtualization. Virtualization is an effective tool for utilities and consideration should be given to ensuring that flexibility is maintained. An approach should consider the required outcome rather than the specifics of how that outcome is achieved.

AZPS also notes that NERC's webpage for this SAR "Project 2016-02 Modifications to CIP Standards", as of 4/11/2016, states the following:

"Also the scope of this work will incorporate existing and future RFIs relating to the CIP-002 through CIP-011 family of standards."

AZPS does not believe any RFIs are addressed in the current SAR. We recommend updating the SAR to reference existing submitted RFIs as appropriate. Finally, AZPS recommends removal from the SAR of functional registrations that are no longer included in the Compliance Registry, e.g., Interchange Authority, Load-Serving Entity and Purchasing-Selling Entity.

Likes 0

Dislikes 0

Response

Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC

Answer Yes

Document Name

Comment

We support the revisions to the SAR.

Likes 0

Dislikes 0

Response

Andrea Jessup - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

BPA agrees with the revised scope of the SAR with three exceptions regarding the "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations –" bullet and sub-bullets:

1. BPA proposes that the SDT clearly identify which function holds the compliance documentation responsibilities.
2. BPA believes the NERC Glossary definition of control center is adequate and should not be revised. The current definition maintains the distinction between control centers and substations.
3. BPA believes no clarification of the 'performs the functions of' language is needed for Attachment 1.

Likes 0

Dislikes 0

Response

larry brusseau - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Laura Nelson - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darin Ferguson - 1,3,5,7 - SERC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - 10

Answer	
Document Name	
Comment	

Texas RE supports those comments suggesting that this project should identify continued areas for improvement within the existing CIP V5 Standards and avoid engaging in a wholesale “rewrite” of the CIP Standards at this point in time. Consistent with this principle, the Standards Drafting Team (SDT) has properly identified the FERC directives from Order No. 822 and the various V5 Tag recommendations as the framework upon which to base the scope of this project.

However, Texas RE believes that the SDT should also take the opportunity to address two other areas to develop a strong record and enhance regulatory certainty around the application of the new suite of CIP Standards becoming effective on July 1, 2016. First, Texas RE agrees with those comments suggesting that the Commission should consider the interaction among the various CIP Standards, including the interaction between CIP-002-5.1 and the rest of the Standards as a group. The SDT may specifically wish to address the interplay between the various bright-line impact categories in the CIP-002-5.1 Standard and the risk assessments associated with the other CIP-005 Standards.

Second, Texas RE recommends that the SDT explicitly consider and determine whether aspects of the various supporting materials associated with the CIP Standards, including a number of Lessons Learned, FAQs, and other guidance documents should be incorporated directly into the CIP Standards themselves. For example, the October 2015 CIP V5 Consolidated FAQs and Answers provided that “HVAV, UPS, and other support systems . . . will not be the focus of compliance monitoring” unless such systems are within an Electronic Security Perimeter. (p. 7). However, some HVAC and other systems may fall within the definition of a BES Cyber System and be subject, among other things, to the categorization requirements set forth in CIP-002-5.1, R1. The SDT could add clarity to the Standards by explicitly considering whether HVAC and other support systems should be (or is already) included within the BES Cyber System definition or conversely carved out of the CIP Standards in certain circumstances. This will encourage reliability and regulatory certainty by permitting entities to look to the Standard language to understand their compliance obligations, as well as produce a transparent record of the rationale underpinning a particular approach.

Changes to SAR Redlined Language

In addition to Texas RE’s suggestions regarding the scope of this project, Texas RE also suggests two additional revisions to the revised SAR language. First, the scope of the CIP Exceptional Circumstances exception language appears vague. Texas RE presumes that the SDT incorporated the recommendations from the Edison Electric Institute and others suggesting primarily that the SDT should consider whether the CIP Exceptional Circumstances exception should be added to additional CIP V5 requirements. Texas RE recommends making this more explicit by revising the SAR

language to state: "In addition, the SDT will review and address whether it is appropriate to include CIP Exceptional Circumstances exceptions within additional CIP V5 requirements."

Second, Texas RE supports the SDT's inclusion of language in the SAR permitting the SDT to make non-substantive changes to the Standards and Guidelines and Technical Basis sections to correct grammar, punctuation, and/or formatting errors. However, it is possible to read the proposed language to suggest that "errata" changes are somehow broader than such non-substantive revisions. Texas RE would suggest clarifying that "errata" changes to the CIP V5 Standards by inserting the word "non-substantive" in front of the word "errata" in the existing redline language.

Likes 0

Dislikes 0

Response

Considerations for Transmission Owner (TO) Control Centers (TOCC) with Capability to Perform Transmission Operator (TOP) Obligations

Project 2016-02 Modifications to CIP Standards

March 14, 2017

Introduction

The “TOCC White Paper” provides background and technical considerations for potential approaches to modifying the applicability of North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Reliability Standards as they relate to the protection of BES Cyber System(s) at Transmission Owner Control Centers performing the functional obligations of a Transmission Operator. The TOCC White Paper was drafted by the standard drafting team (“SDT”) for NERC Project 2016-02 Modifications to CIP Standards (Project 2016-02) for stakeholder consideration and comment. The TOCC White Paper has not been approved or endorsed by NERC. The SDT is using the TOCC White Paper as a standard development tool to collect feedback on the basis for revisions to the CIP standards on this issue, if any.

As outlined in the applicable Standards Authorization Request (SAR), NERC Project 2016-02, addresses the Federal Energy Regulatory Commission (FERC or Commission) Order No. 822 directives and the issues captured in the Version 5 Transition Advisory Group’s (V5TAG) *CIP V5 Issues for Standard Drafting Team Consideration* ([V5TAG Transfer Document](#)). The V5TAG, comprised of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. In the Transfer Document, the V5TAG outlined the issues which it believed required further modification or clarification within the CIP Reliability Standards. The necessary modifications were believed to support effective implementation; critical infrastructure security improvements; and/or consistency in Compliance Monitoring and Enforcement outcomes.

Among other things, the V5TAG Transfer Document proposes that the CIP SDT address the applicability of the CIP Reliability Standards to BES Cyber System(s) for a TO Control Center performing the functional obligations of a TOP. As such, the SAR for Project 2016-02 lists the following issues for the Project 2016-02 SDT to address:

1. The applicability of requirements on a TO’s Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the Bulk Electric System (BES);
2. The definition of Control Center; and

3. The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

To address the issues listed, the SDT identified the following five areas for examination and discussion: (1) the TOCC responsibilities as they relate to TOP functions or tasks within the NERC registration processes; (2) the roles that entity impact analyses and risk assessments play, including the NERC proposed beta criteria; (3) understanding of the phrase "performing functional obligations;" (4) a technical discussion on the capability vs. authority and span of control of BES Cyber System(s) associated with TOCCs; and (5) consideration of potential solutions. Each of these areas is discussed in this TOCC White Paper.

The SDT is seeking stakeholder feedback on its assessment of the TOCC issue area through the associated informal comment form. In particular, the SDT seeks feedback on the potential solutions proposed in this TOCC White Paper as well as any suggestions for alternative solutions.

V5TAG Background

As described in the NERC Project 2016-02 Standards Drafting Team SAR encompassing the V5TAG transfer document issues, there were multiple readings of the language “used to perform the functional obligation of” in CIP-002-5.1a, Attachment 1, criterion 2.12 and recommendations for clarification of:

- The applicability of requirements on a TOCC that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
- The definition of Control Center.
- The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

The V5TAG suggested that the Project 2016-02 SDT consider the following potential options or recommendations for resolution:

- Provide additional clarity or revisions to CIP-002-5.1a, Attachment 1. Specifically around Transmission Owner Control Centers performing the functional obligations of a Transmission Operator, in particular for entities with small or lower-risk Cyber Asset risks.
- Clarify applicability of requirements on a TOCC that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Currently, CIP-002-5.1a indicates that any Control Center performing the actions noted above is to be considered as having BES Cyber Systems categorized as medium impact, if not already identified as high impact. There is no allowance for a low-risk entity performing TOP functions to identify their assets as containing only low impact BES Cyber Systems.
- Revise the definition of Control Center if additional clarity will improve consistency in implementation, compliance and enforcement, and determination of applicability.

The TOCC whitepaper is an effort to fully inform industry about this issue and the SDT needs feedback from all industry participants on the topics in the associated comment form.

Related Issues Not in Scope of SAR

As described in the Standards Processes Manual, a SAR is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards.

Early in the SDT research effort, discussions with stakeholders revealed a potentially significant connection between the TOCC issue and the ERO Registration processes. The SDT explored this path and captured the following information.

In 2014, NERC completed development of a Risk-Based Registration process, which FERC approved in 2015. During the development effort, NERC considered the concept of a registration *lite* for those entities that may perform functional obligations but have less reliability impacts to the BES. These concerns were not specific to a registered function but were entity-dependent having a relationship with the TOCC. The Risk-Based Registration process concluded and determined there was not a defensible position for a registration *lite* concept, but given the remaining concerns, the ERO established NERC-led review panels developed from the Risk-Based Registration process to assess and confirm an impact rating for TOCCs, should the question arise in the future.

The review panel can be utilized for concerns with registration as a TO or TOP if the entity believes the designation it carries to be inappropriate. Entities that may be impacted by a change in a neighboring or fellow registered entity have a chance to participate in the panel process. To be more direct in linkage, if an entity has concerns about applicability of functional performance or tasks – this would not be addressed in a family of standards – but in the tools and programs as defined in the NERC Rules of Procedure (ROP). These are the ordered processes for any type of exception, if you will, from adherence to the standards and requirements.

In discussions with impacted stakeholders, the SDT learned that some TOPs believe they are inappropriately registered as TOPs and, as a result, are disproportionately impacted by the CIP standards. This registration issue is outside the scope of Project 2016-02. The SDT notes, however, that entities may use existing mechanisms to potentially resolve these concerns.

NERC Project 2016-02 Background

On January 21, 2016, the Commission issued Order No. 822, Revised Critical Infrastructure Protection Reliability Standards, approving seven CIP Reliability Standards and new or modified definitions. On March 9, 2016, the NERC Standards Committee (SC) authorized the SAR to be posted for a 30-day informal comment period from March 23 – April 21, 2016. Based on the comments received, the SDT made minor revisions to the SAR which was posted for an additional 30-day informal comment period June 1-30, 2016. The SC accepted the SAR revisions on July 20, 2016.

The purpose of NERC Project 2016-02 is to increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities. To help accomplish this, the SDT will: (1) address the Commission directives contained in Order No. 822, and (2) consider the V5TAG issues identified in the V5TAG Transfer Document.

It is important to note that the V5TAG issues relate to the language developed by the Project 2008-06 Cyber Security Order 706 Standards Drafting Team (706 SDT) as directed in FERC Order No. 706. The NERC Board of Trustees adopted the stakeholder-approved CIP Version 5 standards and FERC approved the standards on January 18, 2006. The Project 2016-02 SDT must consider the V5TAG issues based on the language of FERC Order No. 706 and the intent of the 706 SDT with a subset of the language captured below.

280. The Commission has two concerns regarding the misuse of facilities, and clarifies those concerns here. First, Requirement R1.2.1 requires responsible entities to consider control centers and backup control centers as potential critical assets. In determining whether those control centers should be critical assets, we believe that responsible entities should examine the impact on reliability if the control centers are unavailable, due for example to power or communications failures, or denial of service attacks. Responsible entities should also examine the impact that misuse of those control centers could have on the electric facilities they control and what the combined impact of those electric facilities could be on the reliability of the Bulk-Power System. The Commission recognizes that, when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.

FERC reiterated its position on April 19, 2012 in FERC Order No. 761 (the order approving “Version 4 Critical Infrastructure Protection Reliability Standards”):

57. The Commission recognizes the diverging views among commenters regarding the protection of control centers and control systems afforded under the Version 4 CIP Reliability Standards. In Order No. 706, we stated that “it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.” The Commission maintains this view. However, as we observed in the NOPR, the percentage of control centers to be identified as Critical Assets under Version 4 is 74 percent, which is an improvement over the number currently identified under Version 3. Therefore, it is reasonable to approve Version 4 because it will ensure that more control centers are identified as Critical Assets than are identified under Version 3. However, we continue to expect comprehensive protection of all control centers and control systems as NERC works to comply with the requirements of Order No. 706.

NERC Proposed Beta Criteria

Prior to the SAR, NERC compliance staff participating in the V5TAG recognized that Control Centers covered by the referenced criterion may not all pose the same level of risk to the BES, which is a fundamental aspect of CIP-002-5.1a impact-based categories. To evaluate each Control Center’s risk to the BES, NERC compliance staff developed beta criteria to identify Control Centers that contain medium impact BES Cyber Systems and evaluate the entity risk impact with consideration of a low impact category. The beta criteria are more fully described below.

The first beta criterion of the evaluation posed the following question: “Does the Transmission Owner’s facility operate at least two geographically separate transmission facilities?” If the answer to this beta criterion was no, the TO’s facility would be identified as an asset that contains low impact BES Cyber Systems. If the answer was yes, then the evaluation moved on to the next criterion.

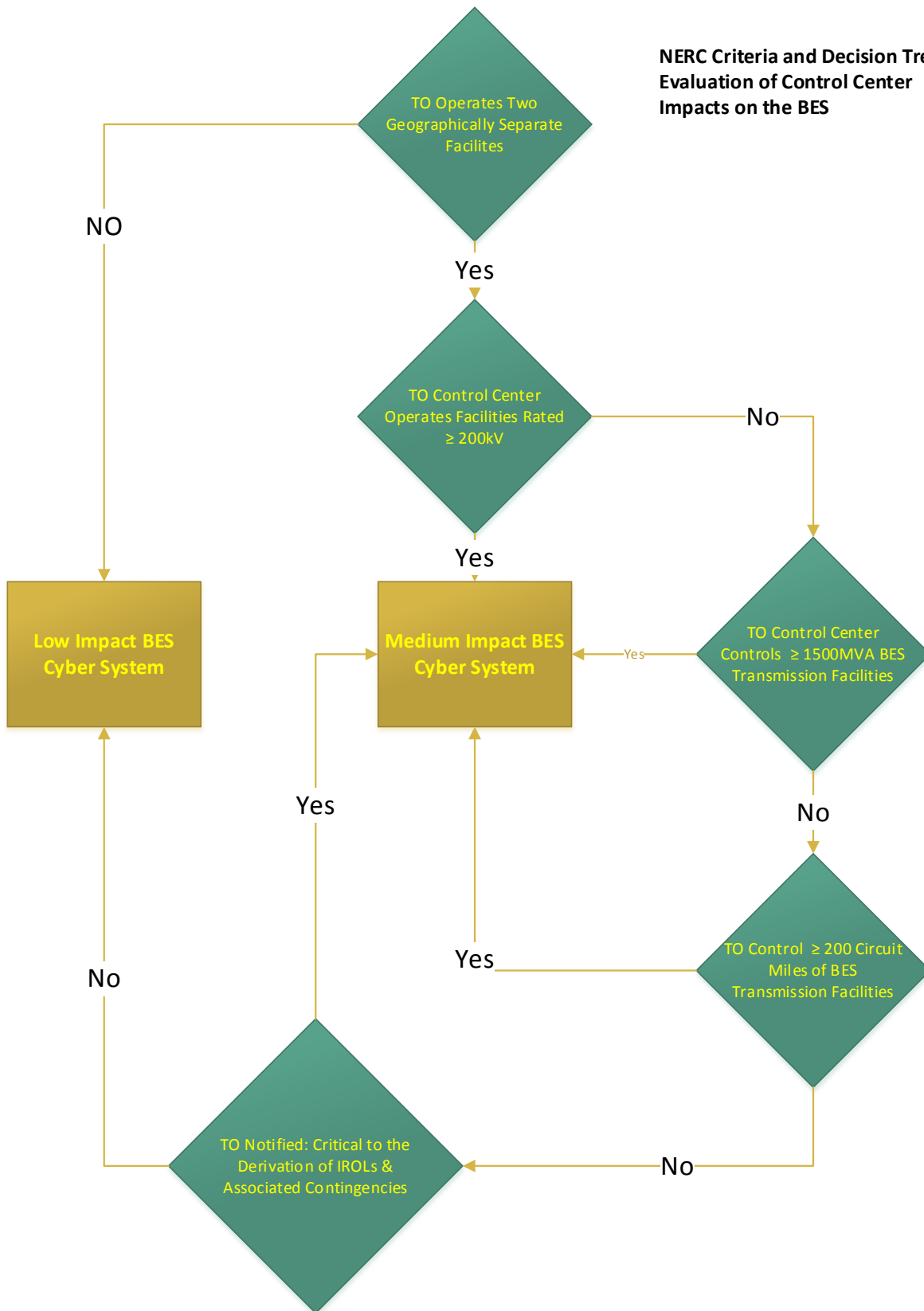
The second beta criterion consisted of the following question: “Do any of the Transmission Facilities operated by the Transmission Owner’s Control Centers operate at or greater than 200 kV?” If the answer to this question was yes, then the evaluation resulted in the Control Center being identified as an asset that contained medium impact BES Cyber System(s). If the answer to this question was no then the evaluation proceeded to the next criterion.

The third beta criterion was labeled as the Group 1 criteria and consisted of three distinct questions:

1. “Does the Transmission Owner control 1500 MVA or more of Transmission capacity at BES Transmission Facilities controlled by the Transmission Owner’s Control Centers?” It should be noted that this is not Transfer Capability through a Transmission Operator Area. Transmission capacity in this criterion was calculated by adding up the Facility ratings of all the Transmission Owner’s BES Transmission Lines and capacitor banks. If the aggregated MVA value was greater than or equal to 1500 MVA, then the Control Center was identified as an asset that contains medium impact BES Cyber System(s). If the answer to this question was no, then the evaluation moved on to the next question.
2. “Does the Transmission Owner control more than 200 miles of Transmission?” This calculation was performed by adding up all of the circuit miles of the Transmission Owner’s BES Transmission Facilities. If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s). If the answer was no then the evaluation moved on to the final question.
3. “Has the Transmission Owner been notified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as having a Facility, controlled by the Transmission Owner’s Control Centers that is critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies?” If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s), if not it was treated as an asset that contains low impact BES Cyber System(s).

The SDT continues to evaluate the beta criteria as an option to pursue. In an effort to clarify the approach as captured, the following flowchart represents the consideration path for execution of the risk assessment.

**NERC Criteria and Decision Tree:
 Evaluation of Control Center
 Impacts on the BES**



Performing Functional Obligations

The SDT delved further into the intent behind the language: “performing the functional obligations of” and identified the following information associated with the creation of this language. The “performing functional obligation of” language was added in CIP-002-4 by the “Project 2008-6 Cyber Security Order Phase II” Standard Drafting Team. The CIP-002-4 Identifying Critical Cyber Assets guideline document references the “functional obligation” language in terms of a “formal delegation” from the registered entity:

http://www.nerc.com/pa/Stand/CIP0024RD/Project_2008-06_CIP-002-4_Guidance_clean_20101220.pdf

The “functional obligations” language first appears in a draft of CIP-002-4. The draft guidance associated with this first introduction of the language offered the following:

Part 1.14 designates all control centers and control systems used to perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA) or Transmission Operator (TOP). EOP-008 requires that RCs, BAs and TOPs “ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.” While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets, control systems at other applicable Responsible Entities that are used to perform the functional obligations of the RCs, BAs, or TOPs must also be designated as Critical Assets. These include control systems at Transmission Owners’ control centers and backup control centers, for example, which have been formally delegated to perform some of these functions. Control systems were specifically called out separately from control centers to ensure that Entities fully evaluate those systems used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator. These control systems may be located at a data center that is not co-located with the control center itself.

As discussed in summary meeting notes from the aforementioned SDT, the SDT commented on the designation of TOCC’s as Critical Assets as follows:

“As discussed in the Reference Document, this requirement is sourced from EOP-008. Control centers performing these functional obligations are considered important enough to require mandatory backup requirements and warrant designation as Critical Assets.”

Given the information discussed above, the relationship to the operations and planning standards vary with different levels of potential impact. To perform functional tasks or obligations, a System Operator must either be certified as a Transmission Operator or Reliability Coordinator (RC) or take direction from a NERC-certified System Operator (Transmission Operator or RC). Maintaining a NERC certification can take significant investment of time and resources, so some System Operators that control BES Transmission Systems do not maintain certification and instead rely on only operating the System when directed by a NERC Certified System Operator. To address the scenario where an individual or entity is 1) performing BES Transmission operations, 2) is not a registered TOP and 3) equipment may have an impact on BES operations, the 706 SDT incorporated the language “used to perform the functional obligations of” to clarify that the equipment used by both NERC-certified System Operators and System Operators operated under the direction of a NERC-certified System Operator had to be protected and fully implement the security objective for protecting equipment used to perform TOP functions. The functional obligations of a TOP are identified in the NERC Rules of Procedure¹, with further examples included in the Functional

¹ http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20161031.pdf

Model and are also summarized in the BES Reliability Operating Services (BROS) in the Guidelines and Technical Basis of CIP-002-5.1a.

1) Capability versus Authority

In terms of CIP-002-5.1a and determination of risk level or impact classification, Attachment 1 criterion 2.12 focuses specifically on those Responsible Entities taking part in or performing both the Transmission Owner and/or the Transmission Operator reliability functions. As stated in the V5TAG Transfer Document, the language “used to perform the functional obligation of,” was intended to “capture entities that perform obligations of a specific registered function, whether they are registered for that function or not.” The statement inherently accommodates the risk that CIP-002-5.1a Attachment 1 is trying to mitigate. Regardless of how a Responsible Entity is registered, to adequately protect the BES, entities must look at not only the intended use but also the potential misuse of the BES Cyber System(s). If a malicious actor is capable of affecting the BES in a negative manner from a given BES Cyber System, that BES Cyber System needs to be protected accordingly to prevent such actions.

Regarding criterion 2.12, this notion calls into question whether it is appropriate to afford BES Cyber Systems protections based on authority to perform actions (registered functions) or capability to perform actions.

For criterion 2.12 in CIP-002-5.1a Attachment 1, it is clear that the intention is to require application of appropriate protections to BES Cyber Systems operated by Responsible Entities that fulfill TOP reliability functions, regardless of registration. An example of this would be a case where there are two Responsible Entities, one registered as a TO, and the other registered as a TOP. If the entity registered as the TO operates a Control Center and follows directives given by the TOP, the TO is clearly operating on behalf of the TOP. In this case, while the TO only does this when authorized by the TOP, the BES Cyber System(s) associated with the TO’s Control Center possess the capability to be used by an unauthorized party to affect the BES, and must be protected as a BES Cyber Asset.

2) Span of Control

The TOP’s span of control is not limited to just Transmission Lines, but to a large number of diverse Transmission Facilities that relate to the reliable operation of the BES. This complexity, together with the interrelated impact from the large number of diverse Functional Entity types that impact TOP functional obligations, makes it very difficult to define a justifiable threshold that can be rationalized considering all the scenarios that could impact Real-time operation for a TOCC.

CIP-002-5.1a, Attachment 1 categorizes BES Cyber Systems into risk based impact levels primarily based on the span of control of the BES Cyber System(s). The premise of this discussion is that the span of control for the TO and TOP functions should be more fully considered to determine whether a risk-basis exists for a low impact categorization for BES Cyber System(s) associated with Control Centers.

Evaluation of Potential Solutions

The SDT evaluated potential solutions (as recommended by V5TAG and others) against the facts and factors uncovered during the SDT research. The associated informal comment form includes questions for stakeholders that are intended to gather additional information and stakeholder positions related to these potential solutions.

1) Propose revisions to CIP-002-5.1a

If the SDT were to take action to respond to the TOCC issue, there are many variations of what may be an appropriate action. The following section proposes potential standard revision options.

a) Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12

The SDT considered the prospect of revising the Attachment 1, criterion 2.12 to add clarity for Responsible Entities. Criterion 2.12 establishes a medium impact level for “Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in high impact rating (H), above.” Under this option, the SDT would propose an impact rating criterion to establish a medium impact rating that would include a lower bound to the criterion. Control Centers with the characteristics listed below would be categorized as assets that contain medium impact BES Cyber System(s), and all others would be identified as low impact BES Cyber System(s). The impact rating criteria would be similar to the NERC proposed beta criteria referenced above. One example of a revised criterion 2.12 is as follows:

Attachment 1: criterion 2.12. Each control center or backup control center not included in the high impact rating (H) above, that is used to operate any of the following:

- Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher
- Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA
- A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
- Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path
- BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA
- Greater than 200 line miles of Transmission Lines

The SDT assessed the potential for such a revision to the criteria and found trade-offs to the proposal. This option could provide added clarity for Responsible Entities and compliance enforcement personnel in determining the assets that are in and out of scope; however, this option could still cause Control Centers with minimal risk to the BES to be identified as medium impact BES Cyber System(s). This could place significant strain on resources of minimal risk entities and the burden as well as benefit may not be commensurate to the risk of those entities.

There will be implications for both newly registered TOs as well as existing TOs. Updated criteria will trigger an analysis and implementation cycles for entities currently in scope under CIP V5 causing rework depending on what type of criteria might be considered. This is a significant consequence for entities that only recently completed implementation of CIP V5 or will still be in the process of completion of the implementation efforts. The update could likely change the impact classification of affected BES Cyber System(s). While this would be one purpose of the revision, resolution for some would be offset by new issues for others.

While the SDT is considering development of a categorization for Control Centers with a low impact rating, FERC Order No. 706 set an expectation that Control Centers would be identified as “Critical Assets,” which correspond to high and medium impact levels in the revised CIP Reliability Standards. Given the overhaul that CIP V5 represents in its expansion of scope to include all BES Cyber Systems, a lower bound for Control Centers may be justifiable.

b) Low Impact Justification Process

Another potential solution is to utilize a justification process that would provide Responsible Entities the opportunity to demonstrate that their Control Center poses a minimal risk/low impact to the BES. As contemplated, a justification process may allow the TO to perform an engineering analysis to demonstrate to the ERO Enterprise that the risk posed by its Transmission Facilities do not warrant protection of the associated BES Cyber System(s) as medium impact. The criteria upon which the ERO would assess the TO’s analysis would need to be developed. This justification process could include a review of the TO’s analysis by an unaffiliated third party.

This justification process approach could provide the clarity requested by the V5TAG and could also provide Responsible Entities a process to demonstrate its actual impact level as demonstrated by engineering studies. However, this additional process could place additional strain on limited resources for Responsible Entities and Compliance Enforcement Authorities to support the positions that certain Control Centers represent less risk or impact to the Bulk Electric System even in a situation specific to misuse or malicious threat actors.

2) No further action by the SDT

The V5TAG presented a valuable opportunity for NERC, the Regions and industry to consider the CIP V5 language under implementation and consider areas that may benefit from added clarity. However, the SDT evaluation must take into account the breadth and diversity of the entities to which the CIP V5 language applies. The language under evaluation by the SDT relative to the TOCC issues raised by the V5TAG was approved by NERC stakeholders through an open and transparent process. The current state reflects that FERC approved language is in effect and currently no direction to modify the language has been given.

In addition, CIP V5 only became mandatory and enforceable on July 1, 2016. Familiarity with the full implications and effectiveness of the standards is still new and untested.

From research and analysis, the option to take no further action could potentially be based on the following reasons:

- The TOCC situation represents individualized company positions and each entity must be evaluated for risk and impact suggesting a widely applicable standard is not appropriate to represent a norm or majority.
- The currently approved language maintains the intent of the CIP V5 language.
- Revision of the Control Center definition is not needed to resolve this issue and has broader implications that are not limited to this project.
- Standards development should not be utilized to solve potential concern about compliance monitoring or enforcement. Alternative ERO tools exist such as the BES Exception Process and NERC led review panels related to Risk Based Registration Processes should be pursued to resolve entity concerns before revising the approved and implemented standard language. If there is validity or need to open the standards for revision, the SDT is asking for this specific feedback.

The SDT understands that, absent an action not proposed within this TOCC White Paper, a decision to take no further action on the TOCC issue area confirms the existing criteria in CIP-002-5.1a Attachment 1, including criterion 2.12 which identifies all BES Cyber System(s) associated with TOCCs performing the functional obligations of a TOP as medium impact.

Next Steps

The SDT requests industry stakeholders consider the discussion and options detailed above and provide informal comments to the SDT. Input to the comment form questions will help confirm the influential facts and circumstances around this issue and aid the SDT in determining recommended actions.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards Transmission Owner (TO) Control Center (TOCC) Performing Transmission Operator (TOP) Obligations

Do not use this form for submitting comments. Use the [electronic form](#) to submit comments on the **Transmission Owner Control Center performing Transmission Operator obligations**. The electronic form must be submitted by **8 p.m. Eastern, Tuesday, April 11, 2017**.

Additional information is available on the [project page](#). If you have questions, contact [Al McMeekin](#) (via email) or at (404) 446-9675.

Background Information

The purpose of Project 2016-02 is to (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document) and (2) address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822. These revisions will increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities.

The V5TAG, which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the V5TAG Transfer Document to formally recommend that the SDT address these issues during the standards development process and to consider whether modifications can be made to the standard language.

Among other things, due to the confusion of the application of the phrase "used to perform the functional obligation of" in CIP-002-5.1a, Attachment 1, criterion 2.12, the V5TAG recommended clarification of:

- The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
- The definition of Control Center.
- The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

This issue was included in the SAR for Project 2016-02 as follows:

- Identify items to be addressed to provide additional clarity and revisions to CIP-002-5.1a Attachment 1. TO Control Centers, specifically around performing the functional obligations of a TOP for small or lower-risk entities should be addressed.
- Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. CIP-002-5.1a indicates that any Control Center performing the actions noted above is to be considered a medium risk asset if not already identified as a high. There is no allowance for an entity performing such functions to identify their BES Cyber System(s) as low impact.
- If necessary and appropriate, the definition of Control Center may need to be revised to provide the additional clarity needed.

The purpose of this comment form is solicit stakeholder feedback to gather input on the V5TAG issue related to TO Control Centers performing TOP obligations to aid the SDT's consideration of this issue. For a discussion of this issue, please reference the associated [TOCC White Paper](#) drafted by the SDT that outlines the background and technical consideration on this issue as well as approaches the SDT is considering to address this issue.

Questions

1. Do you agree with the assertions outlined in the TOCC White Paper (page 8) regarding capability versus authority? Please provide your rationale to support your opinion.

Yes

No

Comments:

2. Do Transmission Owner(s) that have the capability to perform the functional obligations of Transmission Operator(s) present risk(s) to the reliability of the BES significant enough that the Transmission Owner(s) associated Control Center(s) should be designated as medium or high impact? Please provide your rationale including specific practices that may mitigate risks.

Yes

No

Comments:

3. The Project 2008-06 SDT (706 SDT) included the phrase “used to perform the functional obligation of” to provide protection to BES Cyber System(s) that may be misused and impact the BES regardless of which functional entity operates those BES Cyber Systems. For criterion 2.12 in CIP-002-5.1a Attachment 1, does the intent of the “perform functional obligation of” language require additional guidance or clarity? If you believe additional clarity is needed, please provide suggestions and alternatives as well as support for your positions.

Yes

No

Comments:

4. Should the SDT revise the Control Center definition to address the TOCC issue? Please provide rationale to support your position and suggested options or language for consideration.

Yes

No

Comments:

5. The SDT is evaluating options to address the TOCC issue, as described in the TOCC White Paper. Please identify options or propose solutions your entity would support and provide rationale for your position. (See **Evaluation of Potential Solutions** beginning on page 9 of the TOCC White Paper for additional context and discussion.)

Comments:

6. If you support criteria development in CIP-002-5.1a, Attachment 1 to solve the TOCC issue, does your entity agree with the criteria as described in the TOCC White Paper (page 9, subsection **1a. Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12**)? Please provide rationale in the form of detailed technical justification for each criterion you support or alternative criteria and technical justification to support your response.

Yes

No

Comments:

7. Should the considerations proposed for lower risk Transmission Owner Control Centers also be afforded to lower risk Transmission Operator Control Centers? Please provide rationale to support your response.

Yes

No

Comments:

8. If you have additional comments on the TOCC issue or proposed approaches that you have not provided in response to the questions above, please provide them here.

Comments:

Standards Announcement

2016-02 Modifications to CIP Standards Transmission Owner Control Center Performing Transmission Operator Obligations and Virtualization

Informal Comment Periods Open through April 11, 2017

[Now Available](#)

The Project 2016-02 Standard Drafting Team (SDT) is requesting stakeholder input on two issues it is addressing from the Version 5 Transition Advisory Group (V5TAG): (1) the applicability of the CIP Reliability Standards to BES Cyber Systems for a Transmission Owner Control Center performing the functional obligations of a Transmission Operator; and, (2) the use of virtualization in the CIP environment. Two concurrent 29-day informal comment periods are open through **8 p.m. Eastern, Tuesday, April 11, 2017**, for stakeholders to provide feedback on the SDT's approach and draft language for each issue.

Commenting

Use the [electronic form](#) to submit comments. If you experience any difficulties using the electronic form, contact [Wendy Muller](#). Unofficial Word versions of the comment forms are posted on the [project page](#).

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received and determine the next steps of the project.

For more information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance regarding TOCC, contact Senior Standards Developer, [Al McMeekin](#) (via email) or at (404) 446-9675. For additional assistance regarding Virtualization, contact Standards Developer, [Mat Bunch](#) (via email) or at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards | Transmission Owner Control Center Performing Transmission Operator Obligations
Comment Period Start Date: 3/14/2017
Comment Period End Date: 4/11/2017
Associated Ballots:

There were 40 sets of responses, including comments from approximately 159 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the assertions outlined in the TOCC White Paper (page 8) regarding capability versus authority? Please provide your rationale to support your opinion.

2. Do Transmission Owner(s) that have the capability to perform the functional obligations of Transmission Operator(s) present risk(s) to the reliability of the BES significant enough that the Transmission Owner(s) associated Control Center(s) should be designated as medium or high impact? Please provide your rationale including specific practices that may mitigate risks.

3. The Project 2008-06 SDT (706 SDT) included the phrase “used to perform the functional obligation of” to provide protection to BES Cyber System(s) that may be misused and impact the BES regardless of which functional entity operates those BES Cyber Systems. For criterion 2.12 in CIP-002-5.1a Attachment 1, does the intent of the “perform functional obligation of” language require additional guidance or clarity? If you believe additional clarity is needed, please provide suggestions and alternatives as well as support for your positions.

4. Should the SDT revise the Control Center definition to address the TOCC issue? Please provide rationale to support your position and suggested options or language for consideration.

5. The SDT is evaluating options to address the TOCC issue, as described in the TOCC White Paper. Please identify options or propose solutions your entity would support and provide rationale for your position. (See Evaluation of Potential Solutions beginning on page 9 of the TOCC White Paper for additional context and discussion.)

6. If you support criteria development in CIP-002-5.1a, Attachment 1 to solve the TOCC issue, does your entity agree with the criteria as described in the TOCC White Paper (page 9, subsection 1a. Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12)? Please provide rationale in the form of detailed technical justification for each criterion you support or alternative criteria and technical justification to support your response.

7. Should the considerations proposed for lower risk Transmission Owner Control Centers also be afforded to lower risk Transmission Operator Control Centers? Please provide rationale to support your response.

8. If you have additional comments on the TOCC issue or proposed approaches that you have not provided in response to the questions above, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	1,3,4		FirstEnergy Corporation	Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Florida Municipal Power Agency	Chris Gowder	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC

					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hills	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Associated Electric Cooperative, Inc.	Mark Riley	1,3,5,6		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric	3	SERC

						Cooperative, Inc.		
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC

					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC

					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Cowlitz County PUD	Russell Noble	3,4,5		Small Entity Comment Group	John Martinsen	Public Utility District No. 1 of Snohomish County	4	WECC
					Dale Dunckel	Public Utility District No. 1 of Okanogan County	3	WECC
					Bill Hughes	City of Redding	3,4,5,6	WECC
					Russell Noble	Cowlitz County PUD	3,4,5	WECC
					Valentina Guzman	Silicon Valley Power		WECC
					Bill Dearing	NWPPA		WECC
Dominion - Dominion Resources, Inc.	Sean Bodkin	3,5,6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Steven Keller	Southwest Power Pool Inc.	2	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
PPL - Louisville Gas	Shelby Wade	1,3,5,6	RF,SERC		Charlie Freibert	LG&E and KU Energy, LLC	3	SERC

and Electric Co.				PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC
PSEG	Sheranee Nedd	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF
					Karla Jara	PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co	1	RF
ACES Power Marketing	Warren Cross	1,3,4,5	MRO,RF,SERC,SPP RE,Texas RE,WECC	ACES Standards Collaborators	Prairie Power, Inc.	PPI	1,3	SERC
					Arizona Electric Power Cooperative, Inc.	AEPC	1	WECC
					Hoosier Energy Rural Electric Cooperative, Inc.	HE	1	RF
					Sunflower Electric Power Corporation	SEPC	1	SPP RE
					Great River Energy	GRE	1,3,5,6	MRO
					North Carolina Electric Membership Corporation	NCEMC	3,4,5	SERC
					Rayburn Country Electric Cooperative	RCEC	3	SPP RE
					Buckeye Power, Inc.	BUCK	4	RF
					Southern Maryland Electric Cooperative	SMECO	3	RF
					Wabash Valley Power Association	WVPA	3	SERC

1. Do you agree with the assertions outlined in the TOCC White Paper (page 8) regarding capability versus authority? Please provide your rationale to support your opinion.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer No

Document Name

Comment

The assertions do not consider risk or span of control. As described in NERC's proposed beta criteria, Control Centers may not all pose the same level of risk to the BES. In terms of risk to the reliable operation of the BES, the capability to control a single 115KV breaker is considerably different than the ability to control several substations, some of which could cause cascading outages if misoperated.

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - 4 - WECC

Answer No

Document Name

Comment

SVP supports the comments posted by APPA.

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer No

Document Name

Comment

Regarding the functional registration of the Transmission Owner (TO), it is true that entities may perform control actions necessary for supporting BES reliability without the official TOP registration. However, it also true that entities exist with the TOP registration who do not perform operations necessary to maintain BES reliability. A missing element in the discussion of control is the differentiation between those control actions taken to begin and conclude maintenance operations versus actions taken to preserve and protect the reliability of the BES. For small BES networks that have minimal impact on the greater BES, the only objective is to maintain the network for local load. It may sustain an N-1 event without loss of load, but there is no

contingency where BES reliability support is required other than load shedding. Although the associated Facilities are not integral for BES reliability, the owner must register as a Transmission Owner and a TOP if a contractual arrangement is not available for a second entity to assume TOP coverage. In this case, exercise of functional TOP authority is not a risk since it is only related to maintenance; any Control Center strictly associated with this type of network should be low impact. However, the current construct of the Standard mandates medium impact.

We encourage the SDT to remove the language “performing the functional obligations of” and replace it with language that focuses on the risk posed by a Control Center first based on exercise of authority to maintain reliability, and secondarily on Facilities controlled.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer No

Document Name

Comment

While we do agree with the concept that the capability of remotely controlling Facilities via routable protocol is where risk resides, we disagree with addressing registration gaps with the use of the language “used to perform the functional obligation of.” Authority to control is immaterial in the scope of protecting Bulk Electric System (BES) Cyber Systems associated with remote control, as the objective is to allow only authorized control. The same risk is present whether the operator has the authority, or must obtain authorization/direction to execute a remote control operation. Of note, it is necessary to assure the exercise of authority is not impeded; however, for Control Centers not associated with issuing reliability directives, impact designation should be based on the Facilities it controls, not on the vague premise it is performing a functional obligation. The effort to capture all entities performing a functional obligation whether or not they carry the official NERC functional registration defeats the clear assignment of responsibility afforded with the registration process. The Standard Development Process is not equipped to fix registration gaps.

Regarding the functional registration of the Transmission Owner (TO), it is true that entities may perform control actions necessary for supporting BES reliability without the official TOP registration. However, it is also true that entities exist with the TOP registration who do not perform operations necessary to maintain BES reliability. A missing element in the discussion of control is the differentiation between those control actions taken to begin and conclude maintenance operations versus actions taken to preserve and protect the reliability of the BES. For small BES networks that have minimal impact on the greater BES, the only objective is to maintain the network for local load. It may sustain an N-1 event without loss of load, but there is no contingency where BES reliability support is required other than load shedding. Although the associated Facilities are not integral for BES reliability, the owner must register as a Transmission Owner and a TOP if a contractual arrangement is not available for a second entity to assume TOP coverage. In this case, exercise of functional TOP authority is not a risk since it is only related to maintenance; any Control Center strictly associated with this type of network should be low impact. However, the current construct of the Standard mandates medium impact.

We encourage the SDT to remove the language “performing the functional obligations of” and replace it with language that focuses on the risk posed by a Control Center first based on exercise of authority to maintain reliability, and secondarily on Facilities controlled. Considering the operational nature of the Reliability Coordinator (RC), the Control Center for the RC may be designated high impact based on its authority alone. However, it is equally valid to designate the RC Control Center as high impact based on the medium and high impact Facilities it monitors, and when necessary, the reliability impact its directives will have on BES stability. Therefore, in the impact designation for the TO and TOP where the reliability risk varies greatly, it is better to rely on an analysis of the transmission Facilities each Control Center monitors and controls, rather than the function being performed.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer No

Document Name

Comment

Duke Energy fully understands the intent specifically to this section, however we disagree with the approach taken in this document, as it:

1. blurs the lines between what it means to be a registered Transmission Owner and registered Transmission Operator,
2. applies only to the Transmission Owner, yet the Transmission Operator may delegate certain required TOP tasks to other registered and non-registered entities not captured in this document, and
3. approaches the problem with the initial assumption that a “control center” is being operated by an entity not required to operate a control center.

None of the NERC reliability standards applicable to the Transmission Owner require operation of the BES or maintenance of a control center. On the other hand, entities who perform certain tasks operating the BES at the direction of a Transmission Operator may be required to operate out of a control center. The Transmission Owner is an easy target knowing that Transmission Owners in certain RTOs are performing delegated TOP tasks, however their operation of a “control center” has nothing to do with their registration as a Transmission Owner, and everything to do with the TOP tasks that have been delegated.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl & Member G&Ts

Answer No

Document Name

Comment

AECl strongly believes that for the purposes of categorizing BES Cyber Systems located at Control Centers as High or Medium Impact Rating in CIP-002-5.1a and any future versions, the operating personnel at those Control Centers must have independent authority to perform the real-time reliability tasks on the Bulk Electric System (BES). Those BES Cyber Systems located at Control Centers where the operating personnel do not have such independent authority to perform real-time reliability tasks on the BES, should be categorized as Low Impact BES Cyber Systems.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer No

Document Name	
Comment	
<p>ACES believes that capability is more of a delegation function and not an engineering function. As outlined on page 7 of the white paper "To perform functional tasks or obligations, a System Operator must either be certified as a Transmission Operator or Reliability Coordinator (RC) or take direction from a NERC-certified System Operator (Transmission Operator or RC). Maintaining a NERC certification can take significant investment of time and resources, so some System Operators that control BES Transmission Systems do not maintain certification and instead rely on only operating the System when directed by a NERC Certified System Operator." The responsibility, analysis and training goes to the TOP function. These are the risks to the BES. The current v5 requirements are sufficient to protect those transmission systems at the TOCC. Currently, TOCC's are not required to maintain NERC Certification because the risk to the BES is sufficient to their ability to impact the BES.</p>	
Likes	0
Dislikes	0
Response	
<p>David Rivera - New York Power Authority - 1,3,5,6</p>	
Answer	No
Document Name	
Comment	
<p>We agree capability is representative of part of the risk that CIP-002-5.1a is trying to address, however, the Standard was not drafted with plain language to include capability.</p> <p>Capability (physical control) and authority (directing operations) are both important to the operation of the BES and both are currently addressed in CIP-002-5.1a. This assertion is not new. As it stands today, the functional obligations (a.k.a. tasks) found on pg. 37 of NERC Reliability Functional Model – Version 5 does not pertain to a TOCC. From page 24 of the CIP-002-5.1a Guidelines and Technical Basis; "A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System." This should cause cyber systems in TO control rooms to receive the impact rating of the Facility(ies) they physically control.</p>	
Likes	0
Dislikes	0
Response	
<p>Andrew Gallo - Austin Energy - 1,3,4,5,6</p>	
Answer	No
Document Name	
Comment	

Injecting the concept of "capability" vs. "authority" will create confusion and, potentially, inconsistent application of Standards. Specifically, there are no criteria for how to determine if a Standard applies to an entity not included in the "Applicability" section of the Standard. Rather than go through the undefined, unclear exercise of determining whether a Registered Entity has the "capability" of performing activities assigned to another type of Registered Entity, NERC should revise the "Applicability" section of the Standards to ensure they apply to all relevant Registered Entities.

Likes 0

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer

Yes

Document Name

Comment

WECC agrees the capability of a given BES Facility and its associated BCS provides a better representation of the risk to reliability of the BES than does the authority to act, whether or not such authority is unilateral or under direction of the TOP.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

BPA agrees with the assertions. BPA believes that risk to the BES is based on what an entity can do, not what an entity is registered to do.

Likes 1

Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

The NSRF agrees with SDT's assertions regarding capability versus authority. We believe the TO's Control Center, that has the ability to perform switching operations or other functions as directed by a TOP, will possess the capability to be misused by an authorized party to adversely impact the BES, and must be designated as BES Cyber Asset.

Likes 1

Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

Yes

Document Name

Comment

While the word "obligation" in the phrase "perform the functional obligation of" relates to the authority, the purpose of the CIP standards is to require Cyber Security based on risk. This risk is determined by that capability of the equipment and not the authority of the entity. Further, the original intent was not effectively communicated on its implications of registration. Many industry members did not understand that the intent was based upon a functional capability. Many were under the belief that applicability was strictly based upon the registration of the entity.

Likes 3

Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien

Dislikes 0

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer

Yes

Document Name

Comment

PPL agrees with the SDT that it is the capability, not registration, that should drive whether the BES Cyber Systems are required to be protected. Any BES Cyber System that could be used to harm reliability by a malicious actor must be protected, regardless of the registration status of those who actually perform the TOP reliability functions. The current CIP-002-5.1a determination of risk level or impact classification correctly assigns the level of protection needed for different capabilities of Control Centers.

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5**Answer** Yes**Document Name****Comment**

OPG agrees with the assertions outlined in the TOCC White Paper regarding capability versus authority. If the TO's control center has the capability to reduce the reliability of the BES, an unauthorized party may be able to get in if appropriate controls are not put into place. The distinction of capability versus authority does not matter in this case. TO is effectively TOP in terms of potential impact capability for BES reliability. In this case they are performing the same function.

Likes 0

Dislikes 0

Response**Bob Case - Black Hills Corporation - 1,3,5,6 - WECC****Answer** Yes**Document Name****Comment**

"Capability" is the threat to the BES, not "Authority". However, the assertions do not address the practical significance of cyber connectivity at a TOCC facility, and the diminishing return on effort by the threat actor to impact the BES from a small CC. If the risk to the BES by a TOCC facility is deemed more than minimal, then the TO should be registered as an appropriate (selective responsibility) TOP to clear the confusion of "used to perform the functional obligation of".

Likes 0

Dislikes 0

Response**Chris Scanlon - Exelon - 1,3,5,6****Answer** Yes**Document Name****Comment**

Exelon agrees that not every one of the entities in this category present the same risk to the BES. Exelon supports determining appropriate modification to the CIP-002-5.1a criteria as discussed below to establish an impact rating for these Control Centers commensurate with risk.

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

N&ST agrees that what matters to BES reliability is not what uses of a Cyber System are authorized, but what the Cyber System is capable of doing. Bad actors don't ask for permission.

Likes 0

Dislikes 0

Response

Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6

Answer Yes

Document Name

Comment

AZPS agrees with the SDT's assertion that an Entity's capability to perform obligations of a registered function inherently creates the need to protect that Entity's BES Cyber System(s) to prevent negative impact to the BES.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

Texas RE agrees with the Standard Drafting Team's (SDT) statement that "[r]egardless of how a Responsible Entity is registered, to adequately protect the BES, entities must look at not only the intended use but also the potential misuse of the BES Cyber System(s). If a malicious actor is capable of affecting the BES in a negative manner from a given BES Cyber System, that BES Cyber System needs to be protected accordingly to prevent such actions." (TOCC White Paper, p. 8).

This statement, particularly when read in conjunction with the FERC orders cited by the SDT, captures the inherently interconnected nature of the BES and the attendant requirements to design cyber security controls to comprehensively protect all critical assets and avoid creating vulnerable points of entry. FERC articulated precisely this policy in FERC Order No. 761, as referenced by the SDT: “we continue to expect comprehensive protection of all control centers and control systems ...” As noted below, the SDT should carefully consider any exceptions to the bright line Control Center requirements in light of this clearly articulated policy goal to require comprehensive protections of all controls centers and backup control centers.

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer

Yes

Document Name

Comment

AEP believes that criteria 2.12 addresses a tier of facilities with medium impact potential that perform the functional obligations of the Transmission Operator. TOCC are not mentioned in the criteria. One should ask the question: “Do the Cyber Assets employed at a TOCC have the potential to operate transmission breakers?” If so, these CA should be subject to medium impact CIP requirements currently.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

NRG recommends that the drafting team evaluate the term “Control Center” with the association of term “Transmission Owner (TO).” Currently, the NERC definition for the capitalized term “Control Center” is only applicable to RCs, BAs, TOPs and GOPs. If the drafting team feels that the term “TO” should be included in the Control Center definition, we recommend that the drafting team revise the current language in the Glossary of Terms, Rules of Procedure (RoP) and any other official documentation containing this definition. However, any changes have the potential of causing confusion between the terms TO and TOP.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer	Yes
Document Name	
Comment	
While the word “obligation” in the phrase “perform the functional obligation of” relates to the authority, the purpose of the CIP standards is to require Cyber Security based on risk. This risk is determined by that capability of the equipment and not the authority of the entity.	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
While the word “obligation” in the phrase “perform the functional obligation of” relates to the authority, the purpose of the CIP standards is to require Cyber Security based on risk. This risk is determined by that capability of the equipment and not the authority of the entity.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The TOCC White Paper correctly states that the criticality of Control Centers should be judged on the capability of the Control Center rather than its authority. Malicious actors will neither know nor care that they are not authorized to perform disruptive actions; therefore, Control Centers must be protected commensurate with their capability. Also, the SDT should consider a definition for the term “capability” to define what it means in this context.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	

Answer	Yes
Document Name	
Comment	
FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.	
Likes 0	
Dislikes 0	
Response	
Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports NPCC's comments.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the general assertions outlined in the TOCC White paper regarding capability versus authority. Southern agrees that BES Cyber System(s) associated with a TO's Control Center where the TO possesses only the capability, but not the authority, to be used do have some degree of risk. Southern notes that this degree of risk would vary based on the situation, and emphasizes that any required protections should be based upon the actual risk level.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	

Answer	Yes
Document Name	
Comment	
Reclamation supports the statements and recognizes that the statements do not seek to alter registrations.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Review Group recommends that the drafting team evaluate the term "Control Center" with the association of term "Transmission Owner (TO)." Currently, the NERC definition for the capitalized term "Control Center" is only applicable to RCs, BAs, TOPs and GOPs. If the drafting team feels that the term "TO" should be included in the Control Center definition, we recommend the drafting team revise the current language in the Glossary of Terms, Rules of Procedure (RoP) and any other official documentation containing this definition.	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Tacoma Power supports APPA TAPS comments	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
SCE agrees with the assertions regarding capability vs authority. The authority to operate is less relevant to security than the ability for BES elements to be operated from that location. SCE has a concern regarding use of the term "Control Center" to describe "a place where non-NERC Certified operations personnel are located that do have the ability to carry out the functional obligations of the TOP (via voice or procedural direction only) by performing operating actions on BES equipment." This usage does not align well with SCE vernacular. SCE prefers that a defined term not be used; text describing the facility (e.g., facility from which BES elements may be operated by personnel) could be implemented instead.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Lauren Price - American Transmission Company, LLC - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS comments.

Likes 0

Dislikes 0

Response

Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF

Answer

Document Name

Comment

The assertion on capability versus authority is not really clear on the objective. If the objective of assertion is to establish criteria such that if the TO's CC is a conduit for control of BES equipment and the TO's CC should be considered a BES Cyber Asset, but should not necessarily be considered the same impact level as the TOP's, then we agree with the assertion.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

The capability to perform TOP functions may be unique to each Responsible Entity and therefore EEI will let those entities comment individually.

Likes 0

Dislikes 0

Response

2. Do Transmission Owner(s) that have the capability to perform the functional obligations of Transmission Operator(s) present risk(s) to the reliability of the BES significant enough that the Transmission Owner(s) associated Control Center(s) should be designated as medium or high impact? Please provide your rationale including specific practices that may mitigate risks.

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer No

Document Name

Comment

The only proper way to respond to this question is, "maybe." *Some* TOs performing TOP activities *may* present risks to the BES sufficient to designate the BCSs at their Control Centers "high" or "medium" (Importantly, the CIP Standards, as written, do not "designate" Control Centers as "high" or "medium." The CIP Standards apply to high or medium impact **BES Cyber Systems** at a Control Center. Using language such as "high" or "medium" impact Control Centers muddies the Standards and should be avoided.)

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 1,3,5,6

Answer No

Document Name

Comment

A TO Control Center can present risk to the BES based on its capabilities but not based on its functional obligation. This risk should be allowed to be identified as low impact as well as high and medium.

Using the term "functional obligation" avoids the fact that this is specifically a concern about TO's performing switching. The implications of considering TOs "capability to perform functional obligations" could have unforeseen consequences on TOs who perform additional tasks that are redundant to the TOP. Systems located at TO control centers that have a physical control capability should acquire the impact rating from the Attachment 1 criteria that is driven by the assessment of the Transmission Facility(ies). This does not have to be covered by the location of the systems but by the control aspect and being "associated with" a BES Facility.

CIP-014 covers the physical security of the control centers and defines a "pcc" in a manner that recognizes TOs that perform switching. The issue of physical switching as a functional obligation of the TOP has not been clearly specified by NERC. TO control rooms may house medium impact systems that have control functionality and the CIP requirements should already apply accordingly. If any revisions should be made, the Monitoring and Control BROS should be revised to include the TO functional registration for SCADA systems. For example, SPS Cyber Systems may also be located at a TO control room and may have a medium impact rating which is not based on location.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer No

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer No

Document Name

Comment

Reclamation recommends that the impact rating should be commensurate of the risk and TOCCs may be rated as high, medium or low. Not all Transmission Owners that have the capability to perform the functional obligations of Transmission Operators present risks to the reliability of the BES significant enough that the TOCC should be designated medium or high impact. Impact ratings should be based on the specifics of the Control Centers, and the standard should allow for the possibility of a low impact rating.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer No

Document Name

Comment

As stated in the white paper, FERC did say that control centers should be included as a 'Critical Asset'. That statement was before Lows Impact Criteria was created. If that definition had been there, FERC would have said that TO Control Centers should be included in CIP, as a Low Impact Facility. Adding a TOCC from the v1-3 'null set' provides the additional facilities to meet FERC's request that TOCCs be in scope.

Likes 0

Dislikes 0

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl & Member G&Ts	
Answer	No
Document Name	
Comment	
<p>AECI strongly believes that Transmission Owner Control Centers that have the capability, but not the independent authority, to perform the functional obligations of a TOP, do not present significant risks to the reliability of the BES that necessitate their associated BES Cyber Systems to be categorized as a High or Medium Impact Rating. Such Control Centers must receive permission or authorization from a TOP before it can perform real-time reliability tasks on the BES. Therefore, their risk to the reliability of the BES is significantly lower than, and dependent upon, a TOP that has independent authority to authorize another Control Center to take actions on the BES. Again, those Control Centers where the operating personnel do not have such independent authority to perform real-time reliability tasks on the BES, should be categorized as a Low Impact Rating Control Center.</p>	
Likes	0
Dislikes	0
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
<p>Southern Company does not agree that TOs that have the capability to perform the functional obligations of TOPs present risk(s) to the reliability of the BES that should be designated as either medium or high impact. Southern Company believes that in certain instances, the risk to the BES in the case described could and should be considered low impact.</p>	
Likes	0
Dislikes	0
Response	
Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF	
Answer	No
Document Name	
Comment	

Depends on the size of characteristics of the TO's system. Some TO systems are smaller and less critical than some TOP substations. In addition, some TO SCADA systems which provide a conduit for control to a TOP that has the reliability responsibility are not different, no greater cyber security risks, than the TOP communication nodes / data collector which are declared low impact because they only interface with low impact assets.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

No

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy does not agree that Transmission Owner associated Control Centers should be designated as medium or high impact. Transmission Owner associated Control Centers should be designated as Low Impact similar to the GOP function.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer

No

Document Name

Comment

Whether the TO is performing functional obligations of the TOP is strictly a registration issue which should be out of scope of any standard. Allowance of a TO to perform maintenance operations as authorized by the TOP is not necessarily a registration gap. If transmission operations only involve low impact Facilities, it is probable that operations do not include actions to preserve BES reliability. However, TO remote control of a medium impact Facility should identify its Control Center as medium or high impact. Efforts by the SDT to address TO ability to perform functional obligations inappropriately assigns impact level by assuming all TOP obligations are medium impact. Assignment of impact level by addressing the risk level of BES transmission assets the TO controls is a better metric. This also extends to Control Centers of small TOP entities.

Likes 0

Dislikes 0

Response

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC

Answer No

Document Name

Comment

A TO Control Center can present risk to the BES based on its capabilities but not based on its functional obligation. This risk should be allowed to be identified as low impact as well as high and medium.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer No

Document Name

Comment

A TO Control Center can present risk to the BES based on its capabilities but not based on its functional obligation. This risk should be allowed to be identified as low impact as well as high and medium.

Likes 0

Dislikes 0

Response

Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6

Answer No

Document Name

Comment

Although AZPS agrees that Entities performing functional obligations of Transmission Operators may present risk to the reliability of the BES, a general classification may not be appropriate. Rather, classification using engineering studies, independent reviews, and reliability criteria may more accurately identify each Entity's designation.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

No

Document Name

Comment

IID believes the impact rating should be based on the potential risk to reliability of the BES.

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

No

Document Name

Comment

N&ST agrees with the view, presented in the TOCC White Paper, that it might be appropriate to designate some TOCCs as medium or high impact, but only if they meet revised criteria such as the ones presented in the white paper.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1,3,5,6

Answer No

Document Name

Comment

Exelon's position is that not every one of the entities in this category present the same risk to the BES. Exelon supports determining appropriate modification to the CIP-002-5.1a criteria as discussed below to establish an impact rating for these Control Centers commensurate with risk.

Likes 0

Dislikes 0

Response

Bob Case - Black Hills Corporation - 1,3,5,6 - WECC

Answer No

Document Name

Comment

The fact that a TO "used to perform the functional obligation of" a TOP was not registered as a TOP in the first place, suggests that they do not pose a greater than minimal risk to the BES. If the risk to the BES by such a TO is deemed to be more than minimal, then that TO should be registered as an appropriate (selective responsibility) TOP to clear the confusion of "used to perform the functional obligation of".

The option shown on the bottom of Page 9 of the TOCC Whitepaper could be the criteria basis of when a TOCC should be registered as a TOP.

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer No

Document Name

Comment

Whether the TO is performing functional obligations of the TOP is strictly a registration issue which should be out of scope of any standard. Allowance of a TO to perform maintenance operations as authorized by the TOP is not necessarily a registration gap. If transmission operations only involve low impact Facilities, it is probable that operations do not include actions to preserve BES reliability. However, TO remote control of a medium impact Facility should identify its Control Center as medium impact. Efforts by the SDT to address TO ability to perform functional obligations inappropriately

assigns impact level by assuming all TOP obligations are medium impact. As stated, small TOP's should also be provided the opportunity to assume a Low Impact based on impact to the BES.

Assignment of impact level by addressing the risk level of BES transmission assets the TO controls is a better metric. This also extends to Control Centers of small TOP entities.

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - 4 - WECC

Answer

No

Document Name

Comment

SVP supports the comments posted by APPA.

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

No

Document Name

Comment

A TO Control Center can present risk to the BES based on it's capabilities but not based on its functional obligation. This risk should be allowed to be identified low impact as well as high and medium.

Likes 3

Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer

No

Document Name

Comment

The question does not consider risk or scope/magnitude of functional obligations. As stated in Q1, in relation to the risk to the reliable operation of the BES, the obligation to operate a single 115KV breaker is considerably different than the obligation to operate several substations, some of which could cause cascading outages if misoperated. Based on NERC’s proposed beta criteria and FERC’s comments in order 761 (“Therefore, it is reasonable to approve Version 4 because it [74% of Control Centers are high or medium impact] will ensure that more control centers are identified as Critical Assets than are identified under Version 3.”), there appears to be agreement and acceptance that some TO Control Centers will be low impact. The potential risk presented by Transmission Owners having the capability to perform functional obligations of a Transmission operator does not in itself present a level of risk commensurate with a medium or high impact level.

Likes 1 Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer No

Document Name

Comment

BPA believes the impact rating should be based on the potential risk to reliability of the BES. Not all entities have assets under their control that can negatively effect the BES. In certain cases, Control Centers should be considered low impact.

Likes 1 Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer No

Document Name

Comment

WECC does not consider the impact of small TOP or TO Control Centers on the reliability of the BES to be more significant than that of small BA or GOP Control Centers that come into scope as Low impact BES Assets under IRC 3.1. Further, WECC considers cyber security protections required for smaller TO and TOP control centers should be commensurate with their potential impact on the reliability of the BES. WECC supports the development of a Section 3 Low impact Control Center category for smaller TOP entities and/or applicable TO entities who perform the functional obligation of the TOP from one or more Control Centers. Such Low impact TOP Control Centers and applicable TO control Facilities should be afforded the full protections of the CIPv5 Suite of Standards, as applicable for Low impact BES Assets.

Likes 1 Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

However, the risk will depend on the capability, which may be unique to each Responsible Entity.

Likes 0

Dislikes 0

Response

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

SCE believes TOCCs should be designated as high or medium impact only if BES elements can be operated from said facility. If the TO is at a facility when no BES element can be operated, then no risk exists and the TOCC should not be designed as high or medium impact.

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

The SPP Review Group recommends that the drafting team develops some criteria to identify a TO Control Center capable of performing a TOP function obligation that would require a high or medium impact rating.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer Yes

Document Name

Comment

PSEG supports Edison Electric Institute's comments.

Likes 1 PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

To use a specific example, PJM registers as the RC, TOP, and BA for its entire footprint. However, PJM is not capable of directly operating a single switch or breaker. That operational responsibility is delegated to its member companies. Some of these member companies are very large, such as First Energy, Exelon, and Dominion. Failure to require these entities' Control Centers to be protected would place the BES at extreme risk in these areas.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

NRG recommends that the drafting team develops some criteria to identify a TO Control Center capable of performing a TOP function obligation that would require a high or medium impact rating.

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer Yes

Document Name

Comment

AEP believes TOCC facilities may have Cyber Assets that can operate transmission breakers or affect situational awareness on a broad front. TOCC that have Cyber Assets with the span of control currently associated with high impact Criteria 1.3 should be specifically addressed in that criteria.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

Texas RE supports the application of the CIP V5 Standards to Transmission Owner Control Centers. As the SDT noted in the TOCC White Paper, FERC has expressed skepticism regarding whether particular Control Centers could be exempted from the high or medium impact designations. Specifically, in FERC Order No. 706, FERC commented: "The Commission recognizes that, when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset." FERC reiterated this policy in FERC Order No. 761, as referenced by the SDT: "we continue to expect comprehensive protection of all control centers and control systems ..." FERC's statements indicate that it expects all control centers to constitute critical cyber assets and that the explicit requirements associated with medium impact assets should be comprehensively applied to them. FERC further indicates that exceptions to this policy would need to be narrowly tailored and clearly justified.

Texas RE also agrees with the SDT's important observation that Transmission Owner Control Centers are required to satisfy Control Center requirements, including the requirement to have Backup Control Centers, set forth in EOP-008. (TOCC White Paper at 7). In developing the CIP standards, the previous SDT fully considered this issue, as well as the FERC Orders on regarding the application of the CIP Standards to Control Centers, and elected to include Transmission Owner Control Centers within the scope of the Standards. In doing so, the SDT considered a number of comments raising the same issues now identified in this project. The SDT should carefully consider whether it is appropriate to reverse course at this point in time.

In its option to retain the current language, the SDT noted that one rationale is that the "currently approved language maintains the intent of the CIP V5 language." As the SDT further noted, there are a number of procedural mechanisms, including the BES Exception Process and the Risk Based Registration Process that may be better suited to addressing specific entity issues without altering the underlying intent of the CIP V5 Standards as previously considered and adopted. Texas RE supports this approach.

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

OPG believes that all controls applicable to the TOP's control center, as specified in the CIP V5 standards should be applied to the TO's control center in this case. This is applicable for both TO Control Centres Primary and Backup. The CC can be rated High, Medium or Low as per the criteria in the standard. One potential way to mitigate this issue would be to have the TOP take over the TO functions that are really TOP functions.

Likes 0

Dislikes 0

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer Yes

Document Name

Comment

Yes, any Transmission Owner that has the capability to perform the functional obligations of a Transmission Operator and affect the BES presents risk to the reliability of the BES. While the Transmission Owner may only follow the directives given by the TOP, to the extent the Control Center is capable of being used by a bad actor to harm the BES it presents the same level of risk to the BES as if it were solely Transmission-Operator controlled, and as such should be protected in the same way.

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lauren Price - American Transmission Company, LLC - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name	
Comment	
City Light supports APPA TAPS	
Likes 0	
Dislikes 0	
Response	

3. The Project 2008-06 SDT (706 SDT) included the phrase “used to perform the functional obligation of” to provide protection to BES Cyber System(s) that may be misused and impact the BES regardless of which functional entity operates those BES Cyber Systems. For criterion 2.12 in CIP-002-5.1a Attachment 1, does the intent of the “perform functional obligation of” language require additional guidance or clarity? If you believe additional clarity is needed, please provide suggestions and alternatives as well as support for your positions.

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer No

Document Name

Comment

This language seems to be very clear, if a TO operates BES Elements at two or more geographically dispersed locations on behalf of its TOP, whether under its direction or not, such a Facility where this operation occurs meets the definition of a Control Center and performs one or more of the functional obligations of the TOP (i. e., switching BES Elements).

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation

Answer No

Document Name

Comment

The "Perform Functional Obligation Of" criterion is clear as written.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer No

Document Name

Comment

With the present NERC Glossary definitions the phrase “used to perform the functional obligations of the Transmission Operator” easily translates to “used to operate or direct the operation of the transmission facilities.”

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 1,3,5,6

Answer

No

Document Name

Comment

The “perform functional obligation of” language needs to be revised in the Standard. We agree that the cyber risk of Transmission Owners who can open/close breakers that lack decision-making authority should be addressed. The “Perform the functional obligations of” phrase is about authority and not capability and should be removed or replaced with both the applicable registrations and criteria for the identification of high, medium and low risk.

There is no actual list of “functional obligations.” As it stands today, the functional obligations (a.k.a. tasks) are found on pg. 37 of NERC Reliability Functional Model –Version 5. These tasks do not include switching of devices which seems to be the issue here. When referencing “functional obligation” it also needs to be clear if the term refers to all obligations or a specific obligation

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Lauren Price - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name	
Comment	
Criterion 2.12 implies that all Control Centers should be medium or high impact. BPA's position is that this needs to be addressed with a low impact option, based on actual impact to the BES. As part of the solution, functional obligation should be removed.	
Likes 1	Massachusetts Municipal Wholesale Electric Company, 5, Gordon David
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
The language "perform the function obligation of" does not consider risk or scope/magnitude of actions and abilities of the TOCC and is subject to interpretation. The requirement should be risk based and consider the Reliable Operation of the BES. Please see the response to #8 for proposed language for CIP-002.	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
The "Perform the functional obligations of" phrase is about authority and not capability and should be removed or replaced with both the applicable registrations and criteria for the identification of high, medium and low risk.	
Likes 3	Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - 4 - WECC	

Answer	Yes
Document Name	
Comment	
SVP supports the comments posted by APPA.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
With respect to criterion 2.12, the phrase “used to perform the functional obligation of” should be broadened to also include the <i>capability</i> to be used to perform such functional obligations. We suggest the following language as shown in italics: “Each Control Center or backup Control Center used, <i>or capable of being used</i> , to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H) above.”	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG considers that the wording in the white paper is acceptable and should be included in the standard.	
Likes 0	
Dislikes 0	
Response	
Linda Jacobson-Quinn - City of Farmington - 3	
Answer	Yes

Document Name**Comment**

FEUS recommends a strict analysis of transmission Facilities controlled by a Control Center or Backup Control Center. We support the language as proposed by the SDT in Options 1a and 1b as well as the language proposed by APPA and Utility Services. FEUS does not support Option 2 'no action.'

Likes 0

Dislikes 0

Response**Bob Case - Black Hills Corporation - 1,3,5,6 - WECC****Answer**

Yes

Document Name**Comment**

"used to perform the functional obligation of" begs the question of why the TO is not registered as TOP. The criteria shown on the bottom of Page 9 of the TOCC Whitepaper could be the basis of when a TO should be registered as a TOP. "used to perform the functional obligation of" diminishes the intended clarity of the NERC functional model. The functional model needs to be fixed to allow NERC functions to be cleanly mapped to the NERC standards.

Not doing so could result in future similar confusion disputes; e.g. TP used to perform the functional obligation of PA/PC, GO used to perform the functional obligation of GOP, etc.

Likes 0

Dislikes 0

Response**Chris Scanlon - Exelon - 1,3,5,6****Answer**

Yes

Document Name**Comment**

The language "perform the function obligation of" does not consider risk or scope/magnitude of actions and abilities of the TOCC and is subject to interpretation. The requirement should be risk-based and consider the Reliable Operation of the BES.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer Yes

Document Name

Comment

Criterion 2.12 implies that all Control Centers should be medium or high impact. It needs to address a low impact option, based on actual impact to the BES. As part of the solution, functional obligation should be removed.

Likes 0

Dislikes 0

Response

Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6

Answer Yes

Document Name

Comment

AZPS believes that Criterion 2.12 should provide additional clarity to specify characteristics of the obligations that would subject the Entity to the applicability of CIP-002-5.1.

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer Yes

Document Name

Comment

AEP suggests the following wording change to address the impact potential associated with TOCC: "...used to perform or enable the functional obligation of..."

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

NRG would ask the drafting team to provide clarity on the functional obligation of the TOP.

Likes 0

Dislikes 0

Response

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC

Answer

Yes

Document Name

Comment

We agree that “perform functional obligation of” language requires additional guidance or clarity. We agree that the cyber risk of Transmission Owners who can open/close breakers that lack decision-making authority should be addressed.

The “Perform the functional obligations of” phrase is about authority and not capability and should be removed or replaced with both the applicable registrations and criteria for the identification of high, medium and low risk. Suggest modifying Criteria 2.12 to include specific language for the identification of Medium Impact Control Centers which would allow for Low Impact Control Centers.

A proposed criteria 2.12 is

2.12. Each Control Center or backup Control Center not included in the High Impact Rating (H) above and operates any of the following:

- Any transmission Facilities recognized as Medium Impact asset as identified herein.
- Three or more Network Paths (see below) operating between 200 kV and 499 kV, and has an “aggregated weighted value” exceeding 3000 according to the table below. The aggregate weighted value for a single Control Center is determined by summing the “weight value per Path” used in Criteria 2.5 (where Network Path replace Line) for each Network Path the Control Center operates.
- Any transmission Facilities that has been identified as part of a permanent flow gate or major transfer path.

This recommendation also includes the new term Network Path.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer Yes

Document Name

Comment

We recommend retirement of the phrase “used to perform the functional obligation of” as it attempts to correct registration gaps. In its stead, we recommend a strict analysis of *transmission Facilities* controlled by a Control Center or Backup Control Center. We support the language as proposed by Utility Services.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer Yes

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer Yes

Document Name

Comment

PSEG supports Edison Electric Institute’s comments.

Likes 1 PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response	
Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
More clarity is needed. The focus of the phrase “used to perform the functional obligation of” has been control of BES equipment. The NERC definition of Transmission Operator includes the responsibility of maintaining the reliability of its “local” transmission system, and that operates or directs the operations of the transmission Facilities. An entity being a conduit for control of the BES, but having no reliability responsibilities is not performing the functional obligation of the TOP.	
Likes	0
Dislikes	0
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECE & Member G&Ts	
Answer	Yes
Document Name	
Comment	
AECE strongly recommends that the language CIP-002-5.1a Attachment 1, criterion 2.12 should be revised with the underlined text to read as follows: “Each Control Center or backup Control Center, whose operating personnel have independent authority to perform real-time reliability tasks on the Bulk Electric System (BES), used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.”	
Likes	0
Dislikes	0
Response	
Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
The language should include some mention of being “performing functional obligations and tasks from a NERC Certified System Operator”. That is the level where there are the most risk to the BES. All other risks to the BES are covered in v5 for Lows Impact Facilities.	
Likes	0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer

Yes

Document Name

Comment

Reclamation recommends that additional clarity be provided for the following:

- Identify specific function(s) performed by the TOCC and provide examples of operational activities or types of equipment that are at the root of why 2.12 was written
- Identify the frequency at which the specific functions are performed
- Replace the phrase “functional obligation” with language such as “with the ability to operate“ for entities who are not responsible for performing the functional obligation of the TOPs.

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

The review group would ask the drafting team to provide clarity on the functional obligation of the TOP.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer

Yes

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

The phrase “used to perform the functional obligation of” does not address the capability of the TOCC nor does it address the risk to the BES. The impact categorization should be based on a specific impact rating criteria and its associated risk to the BES.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Yes

Document Name

Comment

The phrase “used to perform the functional obligation of” does not consider the capability of the TOCC and its related risk the BES. The impact categorization should be based on the risk to the BES. Please see the comments under question 8 as alternative edits to CIP-002.5.1 Attachment 1.

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer

Yes

Document Name

Comment

As mentioned above, it is a slippery slope to begin having Standards apply to entities not clearly set forth in the "Applicability" section of the Standard. The better approach would be to revise the Applicability section.

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer

Yes

Document Name

Comment

The current is not very clear around distinctions of whether an entity can perform the functional obligation of.... under direction from a High Impact Control Centre or third-party entity or whether they normally perform the functional obligations unilaterally.

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer

Document Name

Comment

We agree that “perform functional obligation of” language requires additional guidance or clarity. We agree that the cyber risk of Transmission Owners who can open/close breakers that lack decision-making authority should be addressed.

The “Perform the functional obligations of” phrase is about authority and not capability and should be removed or replaced with both the applicable registrations and criteria for the identification of high, medium and low risk. Suggest modifying Criteria 2.12 to include specific language for the identification of Medium Impact Control Centers which would allow for Low Impact Control Centers.

A proposed criteria 2.12 is

2.12. Each Control Center or backup Control Center not included in the High Impact Rating (H) above and operates any of the following:

- Any transmission Facilities recognized as Medium Impact asset as identified herein.
- Three or more Network Paths (see below) operating between 200 kV and 499 kV, and has an “aggregated weighted value” exceeding 3000 according to the table below. The aggregate weighted value for a single Control Center is determined by summing the “weight value per Path” used in Criteria 2.5 (where Network Path replace Line) for each Network Path the Control Center operates.

Voltage Value of a Network Path: Less than 200 kV, 200 kV to 299 kV, 300 kV to 499 kV and 500 kV and above.

Weight Value per Network Path: (not applicable), 700, 1300, and (not applicable).

- Any transmission Facilities that has been identified as part of a permanent flow gate or major transfer path.

This recommendation also includes the new term Network Path.

Definition of **Network Path**:

A collection of BES Elements forming a single transmission circuit, and bounded by two or more substations or stations.

Non-BES lines are not included in the BES line count.

Likes	0
Dislikes	0
Response	

4. Should the SDT revise the Control Center definition to address the TOCC issue? Please provide rationale to support your position and suggested options or language for consideration.

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer No

Document Name

Comment

The Control Center need not be revised if the Standard applies to the correct registered functions.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 1,3,5,6

Answer No

Document Name

Comment

Due to the Control Center use by other Standards, we recommend the SDT not revise the Control Center definition to address the TOCC issue, but take some alternative steps to address the TO function.

The term Control Center should only be associated with the Functional Registered entities RC, BA, TOP and GOP. When dealing with TOs, perhaps the term "control room" can be added and defined as: one or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform tasks under the direction of the TOP (specifically BES switching). See #3 above.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer No

Document Name

Comment

The Control Center definition is not only already in use by the CIP Standards, but it is also being leveraged by other Reliability Standards. Any changes to this definition would have a wide impact that cannot be sufficiently assessed by the CIP SDT. Modifying CIP-002-5.1 Attachment is a more efficient and reasonable method to address the TOCC issue.

Likes 0

Dislikes 0

Response

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer

No

Document Name

Comment

SCE believes the Control Center definition does not require revision in order to address the TOCC issue. Additionally, changes to the definition could have a wide impact on many other Reliability Standards. SCE prefers the TOCC issue be addressed as part of guidance section of the CIP-002-5.1a standard.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer

No

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC

Answer

No

Document Name

Comment

Revision of the Control Center definition is not the best way to address the TOCC issue. Southern Company proposes that modification of the criteria in CIP-002-5.1a, Attachment 1 would be the more appropriate method of addressing the TOCC issue.

Likes 0

Dislikes 0

Response

Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF

Answer

No

Document Name

Comment

The present definition includes 3 parts; monitor, control and perform reliability tasks. Any evaluation to determine if a facility is a control center, all 3 parts must be met.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer

No

Document Name

Comment

PSEG supports Edison Electric Institute's comments.

Likes 1

PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

No

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy disagrees with the proposal to revise the definition of Control Center. A TOCC should still fall under the definition of a Control Center if performing any obligation that could affect the reliability of the BES. Also, any changes to the definition of Control Center may adversely impact other Reliability Standards to which the definition currently applies.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer

No

Document Name

Comment

Notwithstanding our negative response, the definition is restrictive to functional registrations (RC, BA, TOP, and GOP), does not differentiate control type – *maintenance* and reliability related operations – under the Transmission Owner registration. Further, the phrase “two or more locations” is unclear whether it includes two breaker locations on the same bus (one address), or two Facilities located geographically at different addresses. However, adding the TO registration can create problems with the term’s use in other standards were official NERC Registration is clearly the intent. While we strongly recommend review of the definition considering all instances of its use, we do not recommend revision strictly for the benefit of the TOCC issue. Rather, we recommend the Transmission Owner’s *BES Cyber Systems used for remote control of transmission Facilities* be addressed either in the applicability section of the Standard as implemented in PER-005-2, or Control Center as applied to the TO in the guidance documentation.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer	No
Document Name	
Comment	
Due to the Control Center use by other Standards, we recommend the SDT not revise the Control Center definition to address the TOCC issue. The SDT is evaluating options to address the TOCC issue, as described in the TOCC White Paper. Please identify options or propose solutions your entity would support and provide rationale for your position. (See Evaluation of Potential Solutions beginning on page 9 of the TOCC White Paper for additional context and discussion.)	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP believes the existing definition is concise and easy to understand. Adding an exception clause would be cumbersome and may lead to misapplication of CIP and other requirements.	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation	
Answer	No
Document Name	
Comment	
The Control Center definition is clear as written.	
Likes 0	
Dislikes 0	
Response	
Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	No
Document Name	
Comment	
AZPS recommends no revisions to the definition of Control Center as it already excludes Entities that do not provide any primary function and, therefore, present minimal risk/low impact to the BES.	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	No
Document Name	
Comment	
N&ST believes the TOCC issue can be addressed by new or modified impact rating criteria, and that the current definition of "Control Center" does not need to be revised.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
The Control Center definition impacts standards other than CIP and should not be modified by the CIP SDT.	
Likes 0	
Dislikes 0	
Response	
Bob Case - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No

Document Name

Comment

The definition in the NERC Glossary is sound. The problem is trying to bring TOs (who are not registered as TOPs) into this definition.

Likes 0

Dislikes 0

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer

No

Document Name

Comment

We suggest maintaining the standards as currently written. Any change to the Control Center definition could create confusion with respect to existing agreements, registrations, etc.

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - 4 - WECC

Answer

No

Document Name

Comment

SVP agrees with the comments posted by APPA.

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

No

Document Name

Comment

While the Control Center definition raises similar concerns in capability and authority through the phrase "...performing the reliability tasks of...", we feel that the current definition can work with the change we've advocated in response to question 5. Further, changing the definition may create problems and concerns with other requirements and standards.

Likes 3

Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer

No

Document Name

Comment

The defined term Control Centers is no longer used only in select CIP standards, but also used in various O&P standards as well. Modifying the defined term to accommodate this narrow issue could have significant impacts on other, non-related standards that result in a decrease in reliability.

Likes 1

Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

No

Document Name

Comment

The NSRF believes that any revision to the definition of Control Center may have unintended consequences by expanding the scope beyond its intended purpose of addressing TOCC issue related to identification of BES Cyber System. Therefore, addressing TOCC issue by proposing to revise CIP-002-5.1a as stated by this paper, is the correct approach. The NSRF believes that any revision to the definition of Control Center may have unintended consequences by expanding the scope beyond its intended purpose of addressing TOCC issue related to identification of BES Cyber System. Therefore, addressing TOCC issue by proposing to revise CIP-002-5.1a as stated by this paper, is the correct approach.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC**Answer** No**Document Name****Comment**

BPA believes that the Control Center definition does not need to be revised. Updates to the criteria for impact ratings of low and medium should be developed.

Likes 0

Dislikes 0

Response**Steven Rueckert - Western Electricity Coordinating Council - 10****Answer** No**Document Name****Comment**

WECC has multiple smaller TO entities, which are experiencing an undue compliance obligation related to resources and financial concerns with the declaration of a Medium TOCC Facility. In WECC's opinion, the protections afforded such smaller TOP and TO Control Centers should be commensurate with the risk posed to the reliability of the BES. However, WECC does not believe the definition of Control Center should be modified (see comment 5 below for additional clarification).

Likes 1

Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response**Lauren Price - American Transmission Company, LLC - 1****Answer** No**Document Name****Comment**

Likes 0

Dislikes 0

Response**Anthony Jablonski - ReliabilityFirst - 10**

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Linda Jacobson-Quinn - City of Farmington - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	

The existing definition does not clearly define or delineate between TOCC and Control Centres that perform responsibilities as defined in the NERC Functional Model.

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

The review group recommends that the Control Center definition be revised to contain the TO if the drafting team chose to go this route. Additionally, we would recommend the drafting team review the definition of the TO in the Functional Model, RoP as well as the NERC Glossary of Terms.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer

Yes

Document Name

Comment

Reclamation recommends the definition of Control Center should be revised or additional guidance be given. The current definition is silent on whether a Control Center is unmanned, periodically-manned or manned 24/7; is used for convenience only; is not critical to the operation of the BES; and/or includes the operation of non-BES facilities.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer

Yes

Document Name

Comment

As mentioned previously, the definition should only include those facilities that required NERC Certified System Operators and Programs.

Likes 0

Dislikes 0

Response

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC

Answer

Yes

Document Name

Comment

No consensus comments
The SDT is evaluating options to address the TOCC issue, as described in the TOCC White Paper. Please identify options or propose solutions your entity would support and provide rationale for your position. (See **Evaluation of Potential Solutions** beginning on page 9 of the TOCC White Paper for additional context and discussion.)

Comments:

The modification of Criteria 2.12 with language that removes the “functional obligation” and includes sub-criteria for the identification of medium impact Control Centers seems the most beneficial solution and would be consistent with the other existing criteria.

Creating an exemption process or a Low Impact justification process that would allow an entity to reclassify the impact level using engineering studies seems costly and would still require some sort of brightlines to measure the results of the studies against.

The “take not further action” option does not resolve either the “functional obligation” issue or the low impact determinations that NERC was attempting to address using the BETA criteria.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

NRG recommends that the Control Center definition be revised to contain the TO if the drafting team chose to go this route. Additionally, NRG would recommend the drafting team review the definition of the TO in the Functional Model, RoP as well as the NERC Glossary of Terms.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Yes

Document Name

Comment

Updates to the criteria for impact ratings of low and medium should be developed.

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

In the existing Control Center definition the functional entities are called out so OPG is of the opinion that TO should also be called out.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl & Member G&Ts

Answer

Document Name

Comment

If the SDT does not accept AECl's revisions proposed in our comments in response to the questions above, AECl recommends the following revision in underlined text to the NERC Control Center definition: "One or more facilities hosting operating personnel that monitor and have independent authority to take actions to control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations."

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response

5. The SDT is evaluating options to address the TOCC issue, as described in the TOCC White Paper. Please identify options or propose solutions your entity would support and provide rationale for your position. (See Evaluation of Potential Solutions beginning on page 9 of the TOCC White Paper for additional context and discussion.)

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer

Document Name

Comment

WECC supports the modification of Attachment 1: criterion 2.12 (Option 1.a) to establish a feasible set of threshold values that would allow smaller TOP and TO entities to provide protections applicable to Low impact BES Assets for their Control Centers under IRC 3.1, similar to the existing Low impact category for BA and GOP Control Centers. If this path is chosen by the SDT, WECC also recommends the first bullet be amended to read,

"Two or more geographically separate (BES) Transmission Facilities operated at 200 kV or higher. "

Option 1.b is insufficiently clear in its current scope. Although the recent SDT meeting (22 March 2017) provided some criteria for Steady State Analysis studies, the application of those criteria set is still relatively unclear. Under this approach a TOP or TO may not have direct access to power flow software or sufficient data to study its system under steady state conditions, although the TO should be able to request a study from its TP. If Option 1.b is chosen by the SDT, it should define which TPL studies would provide data sufficient to demonstrate the entity meets the steady state analysis conditions and could legitimately categorize its Control Centers as Low impact under IRC 3.1.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

BPA would support Option 1a in the white paper with a different set of criterion as shown in question 6. BPA believes that there should be a way for entities to classify a Control Center as low impact if it has minimal impact to the BES. The cost/benefit of classifying all Control Centers as medium impact or higher is not acceptable.

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

Document Name**Comment**

The NSRF agrees with the potential solution # 1 to revise CIP-002-5.1a. NRSF suggests that SDT considers offering both options 1a and 1b as part of the proposed solution. With offering both options, if an entity is designated based on option 1a, however, has lower reliability impact on the BES, then, this entity will have the option to technically justify that its Control Center poses a minimal risk to the BES and be considered low impact.

Likes 0

Dislikes 0

Response**Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name** Dominion**Answer****Document Name****Comment**

Please see the response to #8 for proposed language as an alternate solution to the TOCC issue.

Likes 0

Dislikes 0

Response**Brian Evans-Mongeon - Utility Services, Inc. - 4****Answer****Document Name****Comment**

The modification of Criteria 2.12 with language that removes the “functional obligation” and includes sub-criteria for the identification of medium impact Control Centers seems the most beneficial solution and would be consistent with the other existing criteria. We propose replacing criteria 2.12 with:

2.12. Each Control Center or backup Control Center not included in the High Impact Rating (H) above and operates any of the following:

- Any transmission Facilities recognized as included as Medium Impact asset as identified herein.
- Any transmission Facilities that has been identified as part of a permanent flow gate or major transfer path.
- Three or more Network Paths (see definition below) that:

1 - operate between 200 kV and 499 kV and

2 - have an aggregated weighted value exceeding 3000. The aggregate weighted value for a single Control Center is determined by summing the “weight value per Network Path” according to the table used in Criteria 2.5 (where the “Network Path” replaces “Line”) for each Network Path the Control Center operates.

This recommendation also includes the new term Network Path.

Definition of Network Path:

A collection of BES Elements forming a single transmission circuit, and bounded by two or more substations or stations. A Path may contain several non-bounding substations with one incoming and one outgoing BES lines. Non-BES lines are not included in the BES line count. “Network Path control” is defined as the ability to control any interrupting device that would open the Network Path continuity.

Creating an exemption process that would allow an entity to reclassify the impact level using engineering studies seems costly and would still require some sort of brightlines to measure the results of the studies against.

The “take not further action” option does not resolve either the “functional obligation” issue or the low impact determinations that NERC was attempting to address using the BETA criteria.

Likes 3	Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien
---------	--

Dislikes 0	
------------	--

Response

Val Ridad - Silicon Valley Power - 4 - WECC

Answer

Document Name

Comment

SVP supports the proposed beta-criteria posted by APPA.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer

Document Name

Comment

PPL believes the current standards are acceptable as they relate to the protection of BES Cyber Systems at Control Centers. PPL has several Control Centers which are protected under the CIP standards and have been since 1/1/2010. PPL recognizes our obligations both directly as a Transmission Owner and indirectly as a PJM Member via assigned tasks via our Operating Agreement.

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer

Document Name

Comment

To perform a proper analysis the criteria in option A is required. Therefore OPG support option A as stated in the white paper.

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer

Document Name

Comment

FEUS recommends a strict analysis of transmission Facilities controlled by a Control Center or Backup Control Center. We support the language as proposed by the SDT in Options 1a and 1b as well as the language proposed by APPA and Utility Services. FEUS does not support Option 2 'no action.'

Likes 0

Dislikes 0

Response

Bob Case - Black Hills Corporation - 1,3,5,6 - WECC

Answer

Document Name

Comment

The fact that a TO "used to perform the functional obligation of" a TOP was not registered as a TOP in the first place, suggests that they do not pose a 'greater than minimal' risk to the BES. If the risk to the BES by such a TO is deemed to be more than minimal, then that TO should be registered as an appropriate (selective responsibility) TOP to clear the confusion of "used to perform the functional obligation of".

The option shown on the bottom of Page 9 of the TOCC Whitepaper could be the criteria basis of when a TO should be registered as a TOP.

The scope of the SDT may not allow them to solve this problem by addressing the registration issue, but that appears to be the correct approach to resolve this issue.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1,3,5,6

Answer

Document Name

Comment

Exelon does not support an arbitrary bright line criteria that is not supported by a corresponding technical justification. Rather, Exelon supports development of a risk-based assessment methodology to determine specific impact of each TOCC to BES reliability, similar to the approaches used in CIP-014.

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Document Name

Comment

N&ST supports the use of new and modified criteria such as those presented in the TOCC white paper.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Document Name

Comment

IID supports Option 1a

Likes 0

Dislikes 0

Response

Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6

Answer

Document Name

Comment

AZPS is supportive of the SDT's proposed solution to revise CIP-002-5.1a to add clarity and criterion to identify Control Centers with low impact BES Cyber System(s). However, AZPS recommends a hybrid approach of 1a and 1b where there is clear brightline criteria to identify applicable Control Centers and an option to apply for an exception with technical justification demonstrating low impact to the BES.

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

As discussed above, Texas RE recommends that the SDT take no further action regarding the TOCC issue at this time. Texas RE notes that the scope of the issue remains undefined at this point. Further, it is unclear how either the NERC Beta criteria or an exemption process would be applied, how many entities would be affected by this process, and whether such applications would result in reliability gaps inconsistent with the intent of the CIP V5 Standards to comprehensively address cyber vulnerabilities and require a baseline level of controls at all vulnerability points.

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer

Document Name

Comment

AEP suggests to add a lower threshold to Criteria 2.12 using the proposed changes with the exception of “greater than 200 miles of transmission lines”. And, specifically call out TOCC where needed in the criteria.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Document Name

Comment

NRG has concerns that potential changes to CIP-002-5.1a relating to these topics could have a broader impact on topics such as radial lines and IROL derivations which could change from year to year (these impacts could potentially change a Generator Control Room into a Transmission Control Center). These potential results could be broader impacts to the scope of the CIP-002 standard than intended by the SDT as well as unintended impacts to other standards (non-CIP).

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer

Document Name

Comment

The modification of Criteria 2.12 with language that removes the “functional obligation” and includes sub-criteria for the identification of medium impact Control Centers seems the most beneficial solution and would be consistent with the other existing criteria.

Creating an exemption process or a Low Impact justification process that would allow an entity to reclassify the impact level using engineering studies seems costly and would still require some sort of brightlines to measure the results of the studies against.

The “take not further action” option does not resolve either the “functional obligation” issue or the low impact determinations that NERC was attempting to address using the BETA criteria.

Likes 0

Dislikes 0

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer

Document Name

Comment

We support the modification of Criteria 2.12, but do not believe there is justification for all of the whitepaper’s Criteria. We are not aware of technical justification for 200 miles of Transmission. The method for determining aggregate transmission does not consider the risk to the BES is dependent on the impact to the entire path and not the summation of each line making that path.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer

Document Name

Comment

We have participated in the development of, and support the Utility Services response to this question.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer

Document Name

Comment

The section "Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12" provides the most clarity with the least amount of overhead of the proposed options. These criteria could also be extended to small TOPs to more accurately assign a lower risk to the smallest entities.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer

Document Name

Comment

PSEG supports Edison Electric Institute's comments.

Likes 1

PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response

Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF

Answer

Document Name

Comment

Creation of appropriate low impact TOCC criteria that can be applied to determine a low impact TOP CC will offer a good solution to the industry. This will alleviate the ambiguity of the term “functional obligation of” as it relates to TOPs and TOs. Much of language to date focuses only on the TO being a conduit for BES equipment control by the TOP and ignores that the TOP has the reliability obligation, which the TO does not have.

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC

Answer

Document Name

Comment

Southern Company supports the solution involving revisions to CIP-002-5.1a, Attachment 1. Southern is in favor of an approach that can be uniformly implemented and clearly understood by Registered Entities. Southern has concern that the Low Impact Justification Process would not provide enough specificity.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts

Answer

Document Name

Comment

AECI strongly recommends that the language in CIP-002-5.1a Attachment 1, criterion 2.12 should be revised with the underlined text to read as follows: “Each Control Center or backup Control Center, whose operating personnel have independent authority to perform real-time reliability tasks on the Bulk Electric System (BES), used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.”

If the SDT does not accept AECI’s revisions proposed in our comments in response to the questions above, AECI recommends the following revision in underlined text to the NERC Control Center definition: “One or more facilities hosting operating personnel that monitor and have independent authority to take actions to control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a

Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.” Both of these options would provide the additional clarity that was requested by the V5TAG as documented in the transfer document and the Standards Authorization Request.

If the SDT does not pursue either of the options proposed above, AECI recommends that the team should establish a low impact justification process as identified in the TOCC whitepaper. AECI asserts that a planning assessment, similar to the evaluation identified in TPL-001-4, R4 (Table 1 – Steady State & Stability Performance Extreme Events) can be used to explicitly demonstrate that the facilities under a TO Control Center’s span of control would not cause an Adverse Reliability Impact to the BES if its BES Cyber Systems were rendered unavailable, degraded, or misused. AECI posits that this process has further engineering basis and technical justification than any of the criteria proposed in the associated TOCC whitepaper.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer

Document Name

Comment

ACES would support Option 1, modification to CIP-002-5.1a. We would suggest one additional to the criteria.

Attachment 1: criterion 2.12. Each control center or backup control center not included in the high impact rating (H) above, that is used to operate any of the following:

- • NERC Certified System Operator Program and Staff
- • Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher
- • Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA
- • A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
- • Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path
- • BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA
- • Greater than 200 line miles of Transmission Lines

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer

Document Name

Comment

Reclamation recommends that the phrase “Facilities at two or more locations” be clarified so that non-BES facilities are not included in the definition. Language such as “Only Bulk Electric System Facilities are to be considered when determining if a facility is a Control Center and subject to criteria under IRC 2.12” is recommended. This concept should also be applied to other requirements concerning Control Centers.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer

Document Name

Comment

SCE agrees with the SDT's list of qualifications (on page 9 of the TOCC White Paper) used to identify facilities. SCE agrees with the need to have more specific criteria than currently exists for Criteria 2.12 in the current standard. However, some elements of the proposed bright line Criterion 2.12 for classifying certain TOCCs as low impact appear subjective. For example, the 1500 MVA aggregate transmission capacity and 200 line miles of Transmission Lines, may potentially exclude TOCC which pose significant reliability impact to the BES.

SCE prefers specific criteria in 1a instead of the Low Impact Justification Process proposed in 1b. SCE supports further refinement to Criterion 2.12 as proposed by EEI or others which take into account specific criteria. SCE does not support Option 2 for the SDT to take no further action.

SCE also recognizes the potential need for a low impact justification process, or by a third-party reliability assessment, as discussed on page 10, may provide technical justification to the specific unique circumstances of certain TOCCs.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

Some elements of the proposed bright line Criterion 2.12 for classifying certain TOCCs as low impact seem arbitrary. For example, the 1500 MVA aggregate transmission capacity and 200 line miles of Transmission Lines could exclude TOCCs capable of having pretty significant reliability impacts.

The low impact justification process as discussed on page 10 is a possibility. Low impact classification based on an independent third-party reliability assessment (similar to CIP-014 approach) may be appropriate in the unique circumstances of certain TOCCs. However, such an individualized assessment process may be more work for NERC and the entities involved, but each decision would be case-by-case and have a valid, technical justification unique to the specific TOCC at issue.

An alternative approach is also provided in our comments under question 8.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 1,3,5,6

Answer

Document Name

Comment

As stated above, we would propose revising the Standard, clarification of the term “functional obligation”, as well as changes to the NERC glossary. When dealing with TOs, perhaps the term control room can be defined as: one or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform tasks under the direction of the TOP. The impact rating of the BES associated cyber systems in these control rooms would be not less than the highest impact level of the Facilities they “control” as specified in CIP-002-5.1a, Attachment 1, Section 2, impact rating criteria.

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer

Document Name

Comment

Injecting the concept of "capability" vs. "authority" will create confusion and, potentially, inconsistent application of Standards. Specifically, there are no criteria for how to determine if a Standard applies to an entity not included in the "Applicability" section of the Standard. Rather than go through the undefined, unclear exercise of determining whether a Registered Entity has the "capability" of performing activities assigned to another type of Registered Entity, NERC should revise the "Applicability" section of the Standards to ensure they apply to all relevant Registered Entities.

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer

Document Name

Comment

BC Hydro does not support the NERC proposed Criterion 2.12 nor the proposed Criterion 2.12 replacement from APPA, TAPS for the following reasons:

Control rooms at Medium Impact generating stations provide a centralized location to control the entire assigned portion of the power system or can have the ability to control two or more transmission Facilities. This typically includes the generating station and the attached substation, including the associated transmission lines (138kV-500kV). As such, physical access to control rooms would enable an ill-intentioned individual the ability to affect a large portion of the power system faster than if they had to go to each device in the field individually.

Having said that, most of the additional proposed protections required for Medium Impact BES Cyber Systems at Control Centres are focused on electronic access point malicious communication detections ie. Requiring an Intrusion detection system – CIP-005-5 R1.5), event alerting/logging, and recovery plan testing independent of if there is a control room or not associated with the generating station. Once access to the Medium Impact ESP is gained, control of the attached devices is possible, irrespective of if there is a control room or not at the facility. If the risk is sufficiently high with these generating stations, these additional requirements should be included, but in a manner that isn't tied to if there is a control center or not.

As such, adoption in its current form or as per the proposal below is NOT recommended.

APPA and TAPS proposed Criterion 2.12 revision:

Criterion 2.12. Each Control Center or backup Control Center not included in the High Impact Rating (H) and operates **any** of the following:

• Three or more Network Paths (see below) operating between 200 kV and 499 kV, and has an “aggregated weighted value” exceeding 3000 according to the table below. The aggregate weighted value for a single Control Center is determined by summing the “weight value per Path” shown in the table below for each Network Path the Control Center operates:

Voltage Value of a Network Path

Weight Value per Network Path

Less than 200 kV

(not applicable)

200 kV to 299 kV

700

300 kV to 499 kV

1300

500 kV and above

(not applicable)

• Any transmission Facilities that has been identified as part of a permanent flow gate or major transfer path.

• Any transmission Facilities integral in the execution of restoration plans as required in NERC Reliability Standards.

Proposed Definition of Network Path: A collection of BES Elements forming a single transmission circuit, and bounded by two or more substations or stations. Non-BES lines are not included in the BES line count. “Network Path control” is defined as the ability to control any interrupting device that would open the Network Path continuity.

Likes	0	
-------	---	--

Dislikes	0	
----------	---	--

Response		
-----------------	--	--

--	--	--

6. If you support criteria development in CIP-002-5.1a, Attachment 1 to solve the TOCC issue, does your entity agree with the criteria as described in the TOCC White Paper (page 9, subsection 1a. Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12)? Please provide rationale in the form of detailed technical justification for each criterion you support or alternative criteria and technical justification to support your response.

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer No

Document Name

Comment

SCE agrees with the criteria in the TOCC White Paper and the need for more specific criteria than currently exists for Criteria 2.12 in the current standard.

However, some elements of the proposed bright line Criterion 2.12 for classifying certain TOCCs as low impact appear subjective. For example, the 1500 MVA aggregate transmission capacity and 200 line miles of Transmission Lines, may potentially exclude TOCC which pose significant reliability impact to the BES.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer No

Document Name

Comment

Elements of the proposed bright line Criterion 2.12 for classifying certain TOCCs as low impact seem arbitrary. In particular, the 1500 MVA aggregate transmission capacity and 200 line miles of Transmission Lines could exclude TOCCs capable of having pretty significant reliability impacts.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 1,3,5,6

Answer No

Document Name

Comment

Apply the current Attachment 1 medium impact criteria (2.2, 2.4, 2.5, 2.7, 2.8, 2.9 or 2.10) to cyber systems associated with Transmission Facilities that are located in TO control rooms (this could be added as criteria 2.14 in Attachment 1).

Alternatively, we support the adoption of new criteria through the Standards development process.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer No

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Lauren Price - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

Elements of the proposed bright line Criterion 2.12 for classifying certain TOCCs as low impact seem arbitrary, and may have unintended consequences of mis-classifying certain Control Centers.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer No

Document Name

Comment

Reclamation does not agree with the inclusion of “Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path” in the impact rating criteria for medium impact.

Likes 0

Dislikes 0

Response

Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF

Answer

No

Document Name

TOCC Transmission Capability Calculation.docx

Comment

Will support with the modification

Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher (**recommended modification**)

- Since Facilities are Transmission Lines or Transmission Transformers, there will be a potential conflict with Regional Entity interpretation of “geographically separate”.

Recommendation - change to: Operate BES equipment at 200 kV or higher at 2 or more substations separated by one mile or greater.

Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA (**recommended modification**)

- Lacking the qualifier “BES” Transmission Facilities
- Direct numerical addition of capacitor into the aggregation of 1500 Power System engineering-wise is incorrect.
- There will be a potential conflict with Regional Entity interpretation of how to calculate the 1500MVA.

o Lacks consideration of how to address tielines to neighboring TO

o Lacks consideration of how to address jointed own facilities

o Inappropriately penalties TO that allows interconnection of distribution substation for end-use customer reliability. As an example a 400 MVA BES Transmission Line is tapped with distribution substation should not create Two 400 MVA BES Transmission Lines

Recommendation #1 - **include the attached white paper as a means to calculate the 1500.**

Recommendation #2 – provide an alternative method of calculating the 1500, whereby the TO must select between the two methods. Method 2 would be the total of:

o Peak Customer load connected to the TO BES Transmission Facilities

o BES generation (nameplate) connected to the TO BES Transmission Facilities.

o Incremented Transfer Capability through TO’s system.

A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies (**OK – see response on question 8**)

Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path **(OK – see response on question 8)**

BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA **(recommend deleting)**

- When consider the maximum aggregated MVA capacity of the BES Transmission Facilities being 1500, it will be impossible to achieve a Total Transfer Capability of greater than 1500.

Recommendation - deletion

Greater than 200 line miles of Transmission Lines **(recommend deleting)**

- Lacking the qualifier “BES” Transmission Facilities
- Length of line has no bearing on the cyber security risk.

Recommendation - deletion

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl & Member G&Ts

Answer

No

Document Name

Comment

AECl does not support the proposed criteria that were referenced in the TOCC whitepaper. Transmission systems vary widely in design and operating practices are significantly different throughout the Interconnections. AECl contends that numerous variables exist and unique electrical characteristics of distinct Transmission systems throughout the Interconnections make establishing succinct criteria an impractical approach. Furthermore, AECl contends that the criteria proposed in the associated whitepaper appear to lack technical merit and do not accurately identify a Responsible Entity’s impact on the reliable operation of the BES. For example, the loss or misuse of 200 circuit miles of Transmission Line could have negligible impacts on the Reliability of the BES, based on a wide variety of possible Transmission system configurations. Additionally, a simple summation of Transmission Facility capacities does not accurately measure a Responsible Entity’s potential impact on the reliable operation of the BES.

AECl recommends that the language in CIP-002-5.1a Attachment 1, criterion 2.12 should be revised with the underlined text to read as follows: “Each Control Center or backup Control Center, whose operating personnel have independent authority to perform real-time reliability tasks on the Bulk Electric System (BES), used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.” This revised criterion provides the additional clarity that was requested by the V5TAG as documented in the Standards Authorization Request.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs**Answer** No**Document Name****Comment**

PSEG supports Edison Electric Institute's comments.

Likes 1 PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response**Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA****Answer** No**Document Name****Comment**

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response**Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group****Answer** No**Document Name****Comment**

Although we support revision to Criterion 2.12, we believe the criteria developed in the White Paper lacks established technical justification. Due to the short development time available to resolve the TOCC issue, we strongly advise utilization of established criteria contained in CIP-002-5.1a, Attachment 1. The Utility Services proposed revision of Criterion 2.12 follows this advice, and its answer to this question is supported by this comment group.

Likes 0

Dislikes 0

Response**Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF**

Answer	No
Document Name	
Comment	
NRG supports the suggestion to amend the definition of Transmission Operator.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	No
Document Name	
Comment	
We support the modification of Criteria 2.12, but do not believe there is justification for all of the whitepaper's Criteria. We are not aware of technical justification for 200 miles of Transmission. The method for determining aggregate transmission does not consider the risk to the BES is dependent on the impact to the entire path and not the summation of each line making that path.	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3,5	
Answer	No
Document Name	
Comment	
Remove the 200 mile criteria. AEP believes circuit miles of transmission lines cannot change the impact.	
Likes 0	
Dislikes 0	
Response	
Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No

Document Name	
Comment	
AZPS is supportive of criteria development in CIP-002-5.1, Attachment 1; however, believes that 1500 MVA of facility rating is too stringent. AZPS believes that the minimum appropriate MVA facility rating would be 3000 MVA. Alternately, 1500 MVA peak flow or Total Transfer Capacity (TTC) can be used as the criteria. AZPS recommends replacing the item "Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA" with the suggestions above.	
Likes	0
Dislikes	0
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	No
Document Name	
Comment	
N&ST agrees with all proposed criteria EXCEPT for one based on miles of transmission line(s) controlled by a TOCC (proposed value 200). N&ST does not believe transmission line mileage is a useful indicator of a TOCC's potential impact on BES reliability.	
Likes	0
Dislikes	0
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID supports the following criterion 2.12 update developed by APPA and TAPS, in collaboration with industry input. Any Control Centers that do not fall under the High Impact Rating or this criterion would be classified as Low Impact.	
Likes	0
Dislikes	0
Response	
Chris Scanlon - Exelon - 1,3,5,6	

Answer	No
Document Name	
Comment	
Exelon does not support the revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12 as presented in the TOCC White Paper, as no corresponding technical justification is provided. Rather, Exelon supports development of a Low Impact Justification Process as described in the TOCC White Paper.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
As stated in our response to Question No. 5, we support the existing standards.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Please see the response to #8 for proposed language as an alternate solution to the TOCC issue.	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	

Comment

We would support the modification of criteria 2.12 but do not believe that there is technical justification for all of the criteria included in the white paper.

1. The method for determining aggregate transmission does not consider that the risk to the BES is dependent on the impact of the entire "path" and not the summation of each line making that path.
2. There is no technical justification for the 200 line miles of transmission.

Likes 3

Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien

Dislikes 0

Response**Val Ridad - Silicon Valley Power - 4 - WECC**

Answer

No

Document Name

Comment

SVP agrees with the comments posted by APPA.

Likes 0

Dislikes 0

Response**Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC**

Answer

No

Document Name

Comment

BPA supports the following criterion 2.12 update developed by APPA and TAPS, in collaboration with industry input. Any Control Centers that do not fall under the High Impact Rating or this criterion would be classified as Low Impact.

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer Yes

Document Name

Comment

ACES would support the criteria. Regions and auditors are currently using those process flows as guidance. An entity could still go through the NERC Exception Process for asset removal, if needed. Clearly, small cooperatives who are most at risk for potential Medium Impact Control Centers would appreciate knowing that their status level will not change over time and FERC Commission changes.

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer Yes

Document Name**Comment**

FEUS agrees with the criteria with a proposed modification to the following:

“Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or are **necessary for System Operating Limits** associated with a major transfer path.”

Likes 0

Dislikes 0

Response**Bob Case - Black Hills Corporation - 1,3,5,6 - WECC****Answer**

Yes

Document Name**Comment**

Acknowledge that the TOCC White Paper Page 9 criteria:

- • Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher
 - • Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA
 - • A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
 - • Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path
 - • BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA
 - • Greater than 200 line miles of Transmission Lines
- may need to be further debated for what constitutes greater than minimal impact to the BES.

Likes 0

Dislikes 0

Response**David Ramkalawan - Ontario Power Generation Inc. - 5****Answer**

Yes

Document Name

Comment

While OPG supports the language in the white paper it is not clear how the 200miles criterion was derived.

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

MRO NSRF agrees with the criteria proposed by this paper to solve the TOCC issue. We support the SDT using similar criteria to beta criteria assessment proposed by the NERC compliance staff to evaluate each TO Control Center's risk to the BES. The beta criteria assessment considers that not all Control Centers poses the same risk to the BES reliability and security, and therefore, should be categorized and identified based on their risk impact. Further, this risk impact approach proposed by this paper is aligned with the main purpose of CIP-002.5.1a impact-based categories.

Likes 0

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer

Yes

Document Name

Comment

WECC considers the proposed set of threshold values (Option 1.a) to be an accurate reflection of the risk posed to the reliability of the BES by TOP and TO Control Centers. WECC supports all six of the listed criteria (with the recommended change to the first bullet, cited above in item #5) as a reasonable set of threshold criteria to establish TOP and TO Control Centers containing Medium BCS and agrees all TOP or TO Control Centers that do not meet one or more of these criteria should be considered Low impact BES Assets under IRC 3.1.

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments for this question.	
Likes 0	

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response

7. Should the considerations proposed for lower risk Transmission Owner Control Centers also be afforded to lower risk Transmission Operator Control Centers? Please provide rationale to support your response.

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer No

Document Name

Comment

As stated in our response to Question No. 5, we support the existing standards.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer No

Document Name

Comment

Based on the function and responsibilities of the TOP, a TOP Control Center should always carry at least a Medium Impact rating.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

BPA believes that registration should not determine risk to the BES.

Likes 0

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10**Answer** Yes**Document Name****Comment**

WECC has multiple smaller TOP entities who are also faced with an undue financial and resource compliance obligation without significant gain to the reliability of the BES. As stated above, WECC supports the development of a Low impact Category for TOP Control Centers and for TO who perform the functional obligation of the TOP and who do not meet the criteria for Medium BCS at Control Centers as established by a modified IRC 2.12 under Option 1.a.

Likes 1 Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response**Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF****Answer** Yes**Document Name****Comment**

MRO NSRF suggests that similar considerations be give to the lower risk Transmssion Operator Control Centers as proposed for the Transmission Onwer Control Centers. We believe the functional registration does not exclusively determine the risk an entity poses to the reliability and security of BES, but rather the operational function(s) they perform or the operational ability or control they have. We understand that the NERC compliance staff is considering futher evaluation using the proposed beta criteria assessment. However, revision to the CIP-002-5.1a, Attachment 1, Criterion 2.12 to consider lower risk Transmssion Operator Control Centers similar to TOCC is an effective approach. This will identify impact and categorization at the front-end as part of CIP-002-5.1 assessment.

Likes 1 Massachusetts Municipal Wholesale Electric Company, 5, Gordon David

Dislikes 0

Response**Val Ridad - Silicon Valley Power - 4 - WECC****Answer** Yes**Document Name****Comment**

SVP agrees with APPA's comment that the determination of risk and resulting impact level should be determined in the same way when operation and ownership both have the same capabilities.

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer Yes

Document Name

Comment

Determination of risk and the resulting impact level, should be determined in the same way when operation and ownership both have the same capabilities.

Likes 3

Illinois Municipal Electric Agency, 4, Thomas Bob; Massachusetts Municipal Wholesale Electric Company, 5, Gordon David; Tacoma Public Utilities (Tacoma, WA), 4, Ho Hien

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer Yes

Document Name

Comment

If the ERO and a third party determines that a TOP CC only provides a minimal risk to the BES, then the CC should be low impact. The risk evaluation should determine what level of risk a facility presents rather than an arbitrary label.

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

OPG considers this would be in line with the NERC CIP Risk based approach for compliance.

Likes 0

Dislikes 0

Response

Bob Case - Black Hills Corporation - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Based on the original TO "used to perform the functional obligation of" a TOP issue, it is appropriate that agreed-to inclusion criteria would apply to both TO and TOPs.

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer Yes

Document Name

Comment

There are many small TOP's that pose little risk to the BES. The cost associated with implementing and maintaining a Medium Impact control center prohibitive and do not increase reliability or security proportionate to justify the cost.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1,3,5,6

Answer Yes

Document Name

Comment

Yes. If the SDT decides to use criteria to classify as low impact certain TOCCs performing the functional obligations of a TOP, they should also allow TO control centers to use the same criteria. Both control centers "perform the functional obligations of a TOP," so there's no reason to differentiate between them simply because one is registered as a TO and the other as a TOP. From a reliability operations perspective, both would be equally important.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Yes

Document Name

Comment

Registration should not determine risk to the BES.

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Yes

Document Name

Comment

N&ST believes this should be done for the sake of consistency if for no other reason.

Likes 0

Dislikes 0

Response

Stephanie Little - APS - Arizona Public Service Co. - 1,3,5,6

Answer

Yes

Document Name

Comment

Yes, AZPS believes if a control center is classified as low risk, it should be designated as such irrespective of who operates it.

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer

Yes

Document Name

Comment

AEP believes the potential impact on transmission facilities is not substantially different. TOCC need to be added to applicable existing criteria.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer

Yes

Document Name

Comment

As answered in earlier questions, we support Low Impact Control Centers for Transmission Operators and Transmission Owners.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

NRG supports the considerations proposed applicable to the lower risk TOCC afforded to the lower risk TOP Control Center(CC) . NRG asserts that the potential risks need to be applicable and fair across the board.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer Yes

Document Name

Comment

Due to efforts to close all reliability gaps regarding transmission Facilities, the establishment of small TOP entities who have no real time reliability concerns exist. For example, some TOP entities have only a single real time reliability action they would act on: load shedding in support of stressed BES Facilities outside the small TOP control area. In other words, loss of the small TOP control area may *help* the overall stability of the BES. Since the Transmission Service Provider may off load the small TOP system independently, the small TOP capability is low impact. In those cases where the TOP actions do not necessitate real time response due to the trivial BES assets it controls, the central consideration is whether the BES external to the small TOP is properly protected with appropriate control by other entities.

Likes 0

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer Yes

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

Entities that pose a similar risk to the BES should be treated in a similar manner.

Likes 0

Dislikes 0

Response	
Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports Edison Electric Institute's comments.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
If modifications are made to the criteria in CIP-002-5.1 Attachment 1, these modifications should apply to both Transmission Owner Control Centers and Transmission Operator Control Centers. Southern Company is in favor of consistent application of any modified criteria, regardless of registration.	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
The criteria used for differentiating low impact TO CC carry a similar risk profile if applied to TOP CC. For systems meeting the low impact criteria, the risk to the BES from cyber security is no different for the TO CC operating as a control conduit versus a TOP CC that controls and is responsible for reliability	
Likes 0	
Dislikes 0	

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer Yes

Document Name

Comment

If the CIP standards are truly risk based then a similar set of criteria should be available to TOPs. Smaller entities that are rural should not be considered at the same risk level as a multi-regional urban TOP CC.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer Yes

Document Name

Comment

Reclamation recommends that the definition of Control Center be applied uniformly regardless of ownership.

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

The SPP Review Group supports the considerations proposed applicable to the lower risk TOCC afforded to the lower risk TOP Control Center(CC) . From our perspective, the potential risks need to be applicable and fair across the board.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer Yes

Document Name

Comment

Tacoma Power supports APPA TAPS comments

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

If the SDT decides to modify the CIP-002-5.1 Attachment 1 criteria, then these modifications should apply both to the Control Centers of TOs and TOPs.

Likes 0

Dislikes 0

Response

Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

SCE supports considerations for lower risk Transmission Operator Control Centers. If an entity has justifiable reasoning for a lower risk then it should be considered within the Standard. SCE believes the same criteria should be used to classify as low impact certain TOCCs “performing the functional obligations of a TOP” and TOP, should the SDT pursue applying such criteria.

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer Yes

Document Name

Comment

If the considerations make sense for one type of Registered Entity, they should make sense for another type of Registered Entity.

Likes 0

Dislikes 0

Response

Lauren Price - American Transmission Company, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response**Rachel Coyne - Texas Reliability Entity, Inc. - 10****Answer****Document Name****Comment**

: Please see Texas RE's general comments against revising the CIP v5 Standards to create a generalized exception for certain Transmission Owner Control Centers.

Likes 0

Dislikes 0

Response**Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC****Answer****Document Name****Comment**

No further comments

Likes 0

Dislikes 0

Response

8. If you have additional comments on the TOCC issue or proposed approaches that you have not provided in response to the questions above, please provide them here.

David Rivera - New York Power Authority - 1,3,5,6

Answer

Document Name

Comment

The CIP-002-5.1a Standard (and possibly the NERC Glossary) should be modified to clarify all the concerns brought up with TOCC. This whitepaper mentions many of the key concerns, but does not completely address them all. In particular:

- We believe the term Control Center is associated with registered entities (RC, BA, TOP, GOP), therefore a new term should be created for TOCCs (as referenced in the whitepaper), such as 'CIP Control Facility' or 'TO control room'.
- The whitepaper implies that the phrase "perform functional obligation of" should be interpreted as the BES Cyber System capability at a control facility. However, CIP-002-5.1a guidance indicates otherwise. Clarity on this point is critical.

NYPAs position is that the CIP Standard or NERC Glossary be revised to address the concerns raised and attempted to be addressed. Given the validity of the concerns described in the white paper and FERC Order, CIP-002-5.1a should be modified through the NERC balloting process and include an implementation schedule. The Standard's use of "Control Center" and "perform the functions of a Transmission Operator" are terms of particular import with NERC and its registered entities, which should not be altered for convenience through any lesser form of revision.

Likes 0

Dislikes 0

Response

Melanie Seader - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

As indicated in the comments under question 3, the language "used to perform the functional obligations" does not consider the capability of the TOCC and its related risk to the BES.

We provide the following three modifications as an alternative for the SDT to consider in addressing the TOCC issue:

First, modify CIP-002.5.1 Attachment 1, criteria 1.3 to:

Each Control Center identified as meeting CIP-014 R1.2 (as modified by R2.3, if applicable) and any backup Control Centers to these Control Centers.

Second, modify CIP-002.5.1 Attachment 1, criterial 2.12 to:

Each Control Center or backup Control Center that operationally controls one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 not included in 1.3, or meets one of the following conditions:

- A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
- Facilities that have been identified as part of a permanent flow gate or major transfer path.

Third, to address TOP Control Center gaps left by the new criterion 1.3 and 2.12, add the following criterion:

1.5. Each TOP Control Center not included in 1.3 and which provides operational directions to a TO Control Center meeting 1.3.

2.14. Each TOP Control Center not included in 1.3, 1.5, and 2.12 which provides operational directions to a TO Control Center meeting 2.12.

From the CIP-014 GTB: “A primary control center operationally controls a Transmission station or Transmission substation when the control center’s electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity.”

Tying 1.3 to CIP-014 covers the third party review discussed by the SDT that ensures that high impact CCs are identified. Medium impact is then based purely on the medium impact criterion under section 2 of CIP-002-5.1 for both TO and TOP CCs; and CIP-002-5.1, section 3, part 3.1 covers all other Control Centers to meet FERC’s desire for “comprehensive protection of all control centers and control systems.”

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Document Name

Comment

The SPP Review Group suggests that the concerns could be resolved better through the NERC Registration process for categorization of the BES Cyber Systems. For example, if the BES Cyber System is used for the obligations of the TOP, but is located in the control center of a TO, the TO control center would either be Medium or High.

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC,SPP RE,RF, Group Name ACES Standards Collaborators

Answer

Document Name

Comment

Doing nothing is not an option. Smaller cooperatives are concerned that the current group of TO letters that were sent out from NERC will not satisfy FERC's concern that the issue has been addressed and the issue has closure.

Thank you for your time and consideration.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl & Member G&Ts

Answer

Document Name

Comment

AECl thanks the SDT for its efforts to address TOCC issue.

Likes 0

Dislikes 0

Response

Terry Volkmann - On Behalf of Small TO CC group - 1,9 - MRO,SERC,RF

Answer

Document Name

Comment

Yes, many of the low impact criteria for the TO CC can change with less advance notice the time needed to elevate the BES Cyber Assets from low impact to medium impact. The TOCC criteria should allow 24 months transition from low to medium from the time of discovery. This is consistent with the V2 and V3 implementation plan for newly classified cyber assets.

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer

Document Name

Comment

PSEG supports Edison Electric Institute's comments.

Likes 1

PSEG - PSEG Fossil LLC, 5, Kucey Tim

Dislikes 0

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

Document Name

Comment

FMPA supports the comments developed by APPA / TAPS which were submitted by Utility Services, Inc.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3,4,5, Group Name Small Entity Comment Group

Answer

Document Name

Comment

Thank you for the opportunity to comment on this issue.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3,5

Answer

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE does not have additional comments.

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name

Comment

City Light supports APPA TAPS

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Document Name

Comment

(none)

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer

Document Name

Comment

FEUS appreciates the efforts by the SDT. It is important for the SDT to respond to the TOCC and ensure small TOP's are considered. FEUS does not support Option 2 "No further action by the SDT." While the current language was approved through the Standards Process, the language 'performing the functional obligations of' became confusing and upon implementation was determined be different than initial interpretation by many Registered Entities.

Likes 0

Dislikes 0

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer

Document Name

Comment

PPL agrees with the SDT that the current standards reflect FERC-approved language and there is currently no direction from FERC to modify the language.

PPL would support a NERC approved process whereby a TO with a Control Center could petition their Reliability Coordinator to be classified as a Low Impact BES Asset with approval by the respective Regional Entity. E.g. this process could be part of the new ERO Enterprise Risk Based Compliance Monitoring and Enforcement Program issued by NERC.

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - 4 - WECC

Answer

Document Name

Comment

Thank you for the opportunity to comment on this issue.

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

Document Name

Comment

Thank you for the opportunity to present these concepts.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer

Document Name

Comment

Although “standards development should not be utilized to solve potential concern about compliance monitoring or enforcement”, it should be acceptable to use it to clarify expectations in order to ensure that the requirement is understood so that proper controls are applied. As discussed in the White Paper, the phrase “perform the functional obligations” is not clearly understood. As described at the beginning of the standard, the Purpose of the CIP standards is “to identify and categorize BES Cyber Systems ...commensurate with the adverse impact that ... those BES Cyber Systems could have on the reliable operation of the BES.” As indicated in the response to Question 2, the language “perform the functional obligations” is very broad and does not consider adverse impact to the reliable operation of the BES. As used, “reliable operation” is not defined. However, Reliable Operation is defined in the NERC Glossary as, “operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

In the spirit of the Purpose statement and NERC defined term Reliable Operation as well as providing “bright line” criteria, Dominion proposes that Sections 1.3 and 2.12 be modified as follows:

1.3) Each Control Center identified as meeting CIP-014 R1.2 (as modified by R2.3, if applicable) and any backup Control Centers to these Control Centers.

2.12) Each Control Center or backup Control Center that operationally controls one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 not included in 1.3, or meets one of the following conditions:

- A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies.
- Facilities that have been identified as part of a permanent flow gate or major transfer path.

Additionally, 2 new requirements would be required to cover gaps left by 1.3 and 2.12 only applying to TOCCs.

1.5) Each TOP Control Center not included in 1.3 and which provides operational directions to a TO Control Center meeting 1.3.

2.14) Each TOP Control Center not included in 1.3, 1.5, and 2.12 which provides operational directions to a TO Control Center meeting 2.12.

- From the CIP-014 GTB: “A primary control center operationally controls a Transmission station or Transmission substation when the control center’s electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity.”

Additional rationale:

Tying 1.3 to CIP-014 covers the third party review discussed by the SDT that ensures that high impact CCs are identified. Medium Impact is then based purely on the Section 2 bright line criteria for both TO and TOP CCs. 3.1 covers all other Control Centers to meet FERC’s desire for “comprehensive protection of all control centers and control systems”.

Likes	0
Dislikes	0
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	

Comment	
N/A	
Likes	0
Dislikes	0
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC's position is clearly stated in items 1-7 above. WECC does not have additional comments.	
Likes	0
Dislikes	0
Response	

Per Nathan Mitchell of APPA, comments submitted by Utility Services are to be considered APPA comments

Additional comments received by Brian Evans-Mongeon of Utility Services

Proposed change to CIP-002-5.1 Attachment 1, Criteria 2.12

Medium Impact Criteria 2.12 - Each Control Center or backup Control Center *used to perform the functional obligations* of the Transmission Operator not included in High Impact Rating (H), above.

Control Center Definition

One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to *perform the reliability tasks*, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

Proposed Revision to Criteria 2.12

Each Control Center or backup Control Center not included in the High Impact Rating (H) above and operates any of the following:

- Any transmission Facilities recognized as included as Medium Impact asset as identified herein.
- Any transmission Facilities that has been identified as part of a permanent Flowgate or major transfer path. Or
- Three or more Network Paths (see definition below) that:
 1. operate between 200 kV and 499 kV and
 2. have an aggregated weighted value exceeding 3000. The aggregate weighted value for a single Control Center is determined by summing the “weight value per Network Path” according to the table used in Criteria 2.5 (where the “Network Path” replaces “Line”) for each Network Path the Control Center operates:

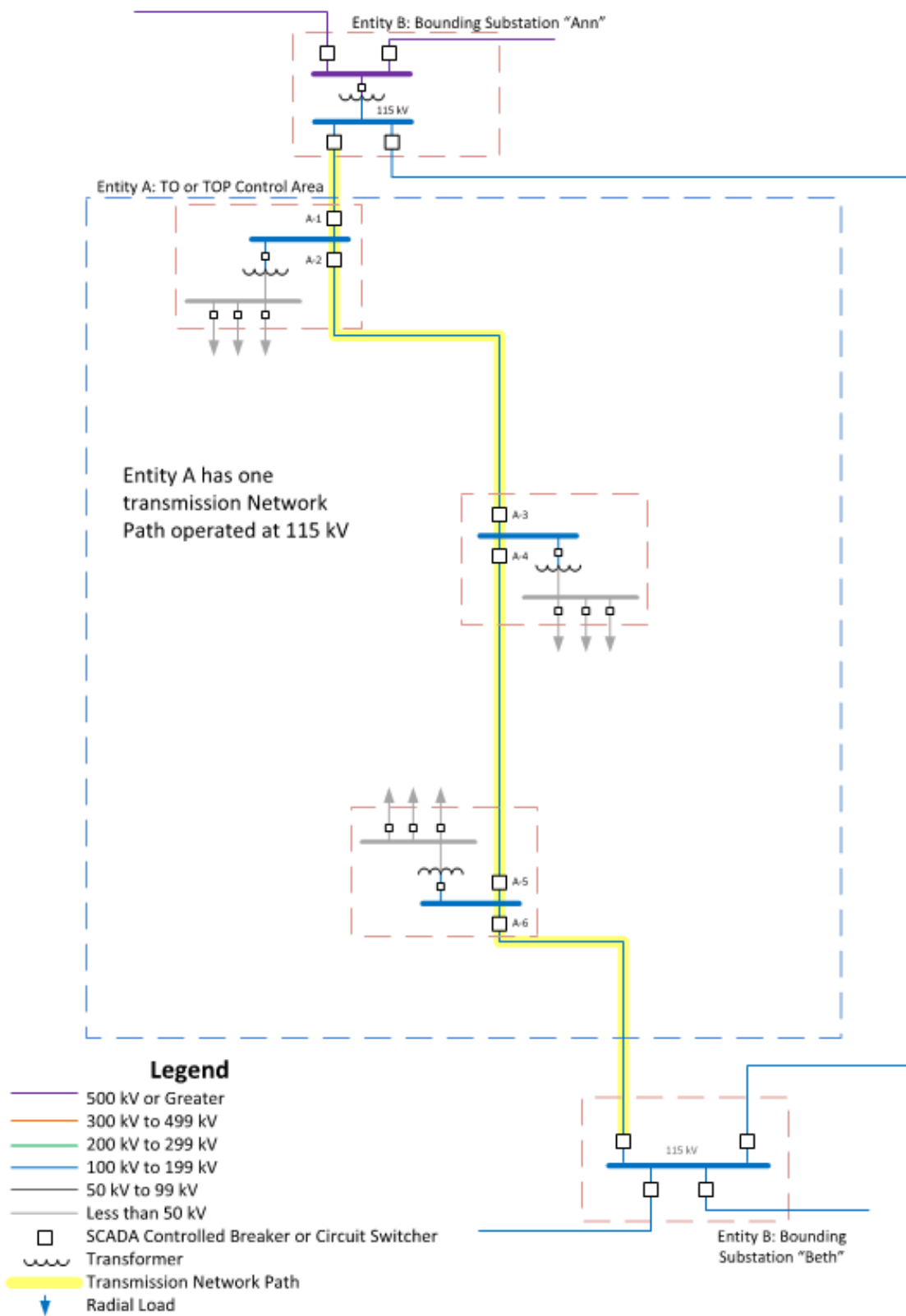
Voltage Value of a Network Path	Weight Value per Network Path
Less than 200 kV	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	(not applicable)

Definition of Network Path:

A collection of BES Elements forming a single transmission circuit, and bounded by two or more substations or stations. A Path may contain several non-bounding substations with one incoming and one outgoing BES lines. Non-BES lines are not included in the BES line count. “Network Path control” is defined as the ability to control any interrupting device that would open the Network Path continuity.

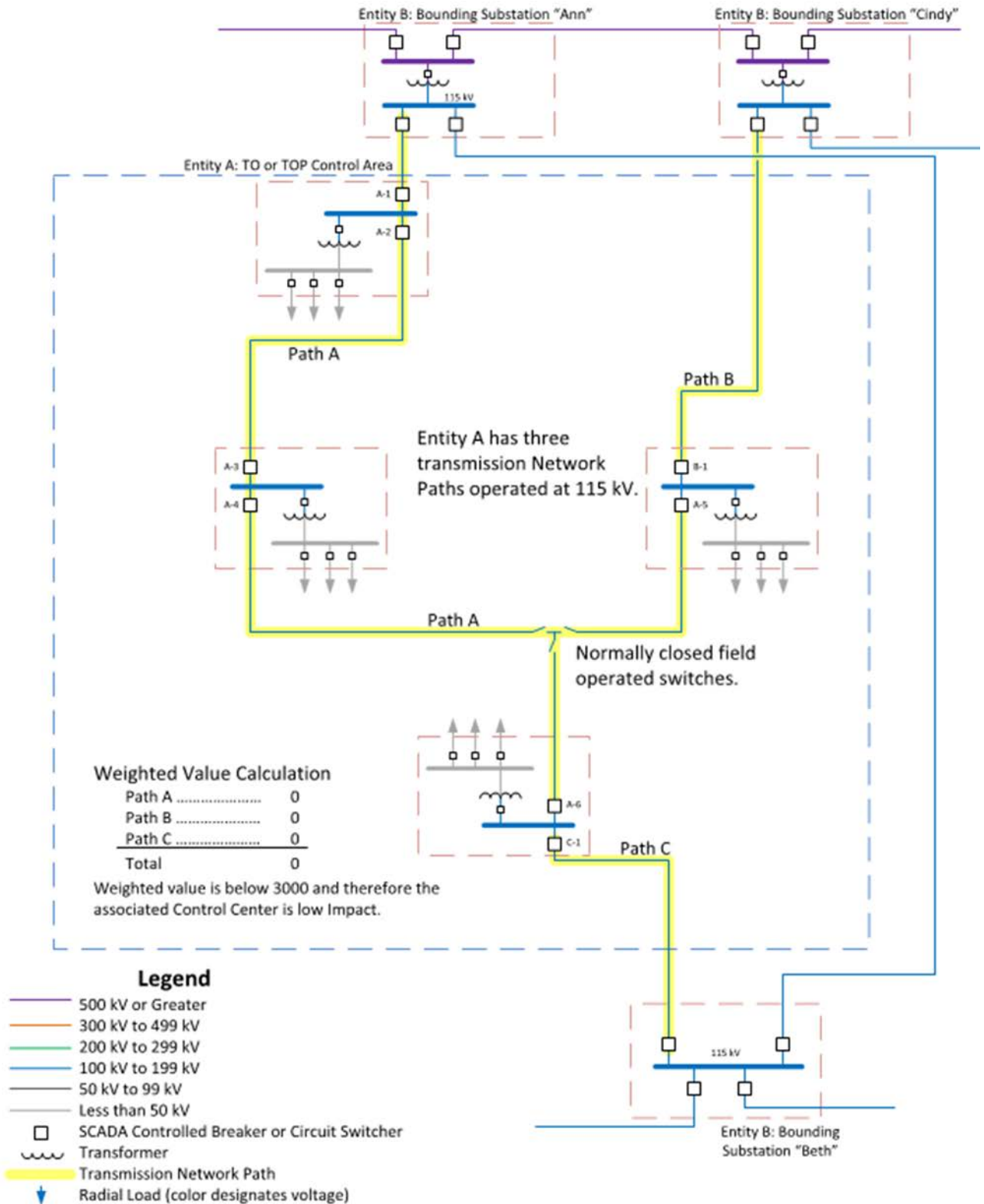
Transmission Network Path

Example A – Simple Two-Station Bounding Path



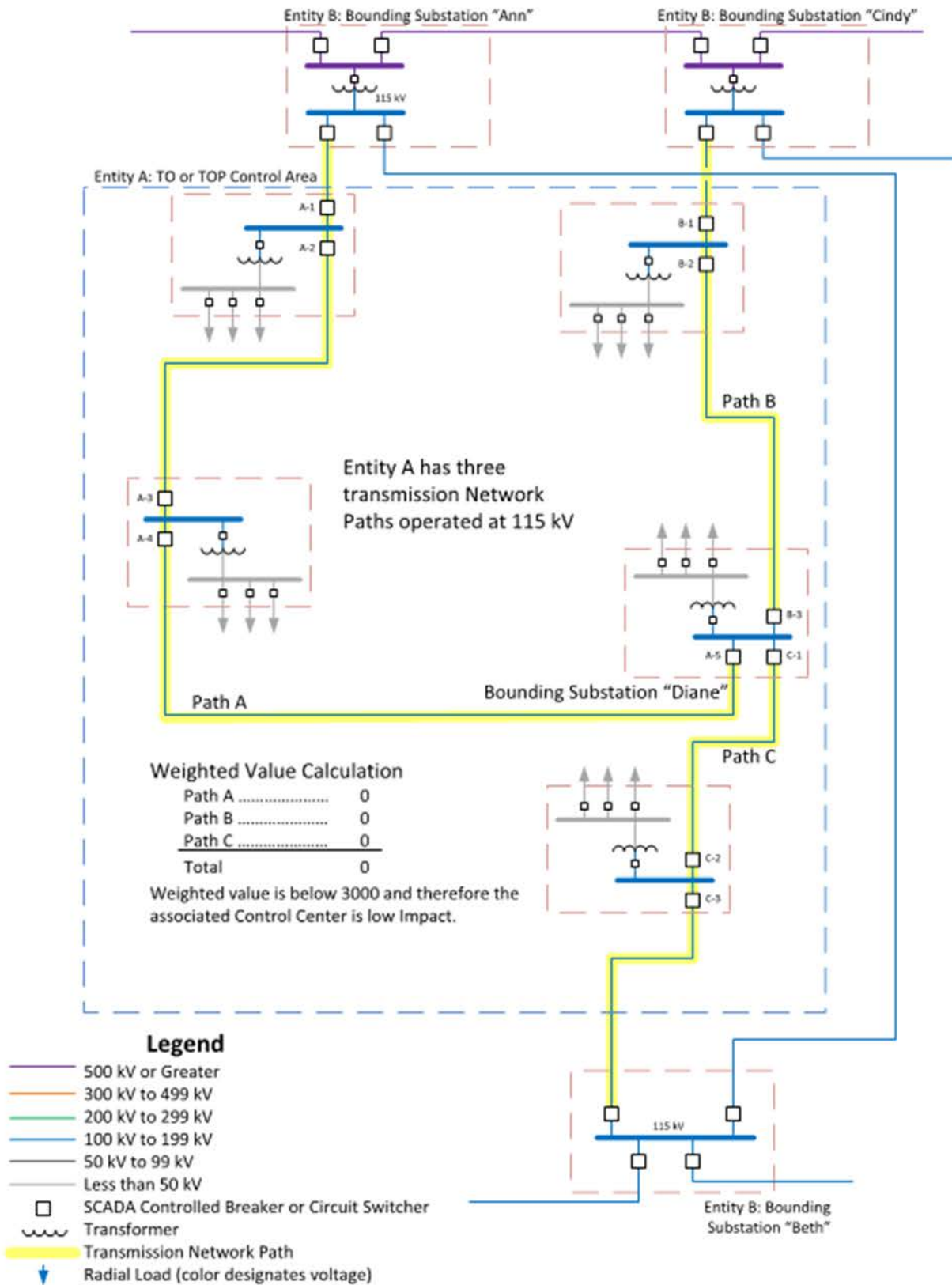
Transmission Network Path

Example B – Three-Station Bounding with Transmission Tap.



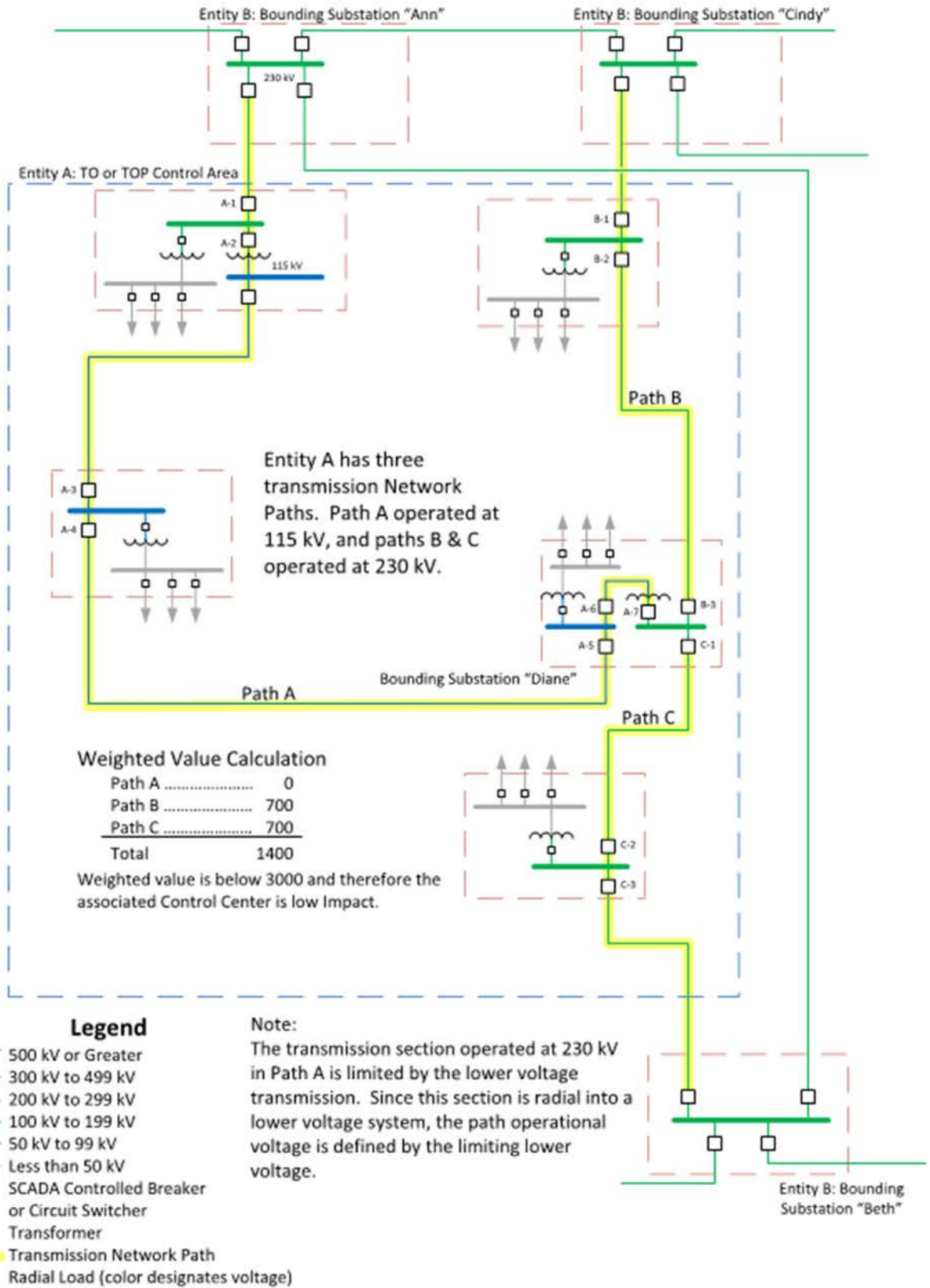
Transmission Network Path

Example C – Three-Path System



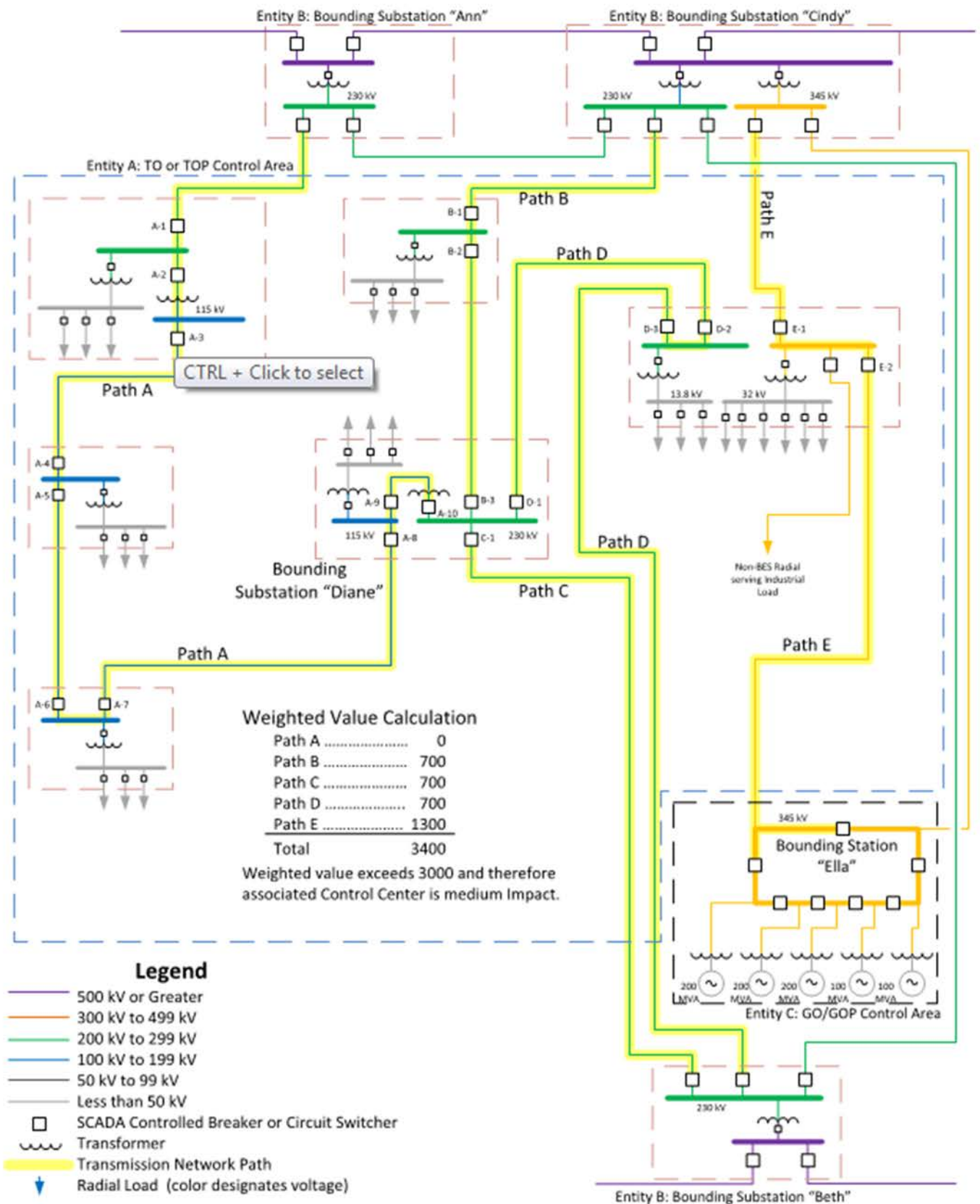
Transmission Network Path

Example D – Multi Voltage System



Transmission Network Path

Example E – Control Area Resulting in Medium Impact Control Center



Reliability Standard Audit Worksheet¹

CIP-002-6 — Cyber Security — BES Cyber System Categorization

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X	X	X	X		X			X	X		
R2	X	X	X	X		X			X	X		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

DRAFT NERC Reliability Standard Audit Worksheet

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

DRAFT NERC Reliability Standard Audit Worksheet

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i.** Control Centers and backup Control Centers;
 - ii.** Transmission stations and substations;
 - iii.** Generation resources;
 - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above*.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

* See the full text of CIP-002-6 for this reference.

Registered Entity Response (Required):

Question 1: Do you share compliance responsibility for this Requirement with another Responsible Entity?

Yes No

For example, is any BES Cyber System located at a shared facility?

If “Yes,” list the following for each asset for which compliance responsibility is shared:

- 1. Asset name or designation.
- 2. Formal agreement or other document describing the shared compliance responsibility, if any.
- 3. Other information regarding the shared compliance responsibility that may be useful to the audit team in determining the appropriate audit scope and approach for the asset.

Note: A separate spreadsheet or other document may be used to provide all or part of this information. If so, provide the document reference below.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-6, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the Responsible Entity has a process to identify each high impact BES Cyber System, each medium impact BES Cyber System, and each asset that contains a low impact BES Cyber System.
	Verify the above process considers all of the following: <ul style="list-style-type: none"> i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 of the Standard.
	Verify the Responsible Entity has identified each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset.
	Verify the Responsible Entity has identified each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset.
	Verify the Responsible Entity has identified each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any.

Auditor Notes:

DRAFT NERC Reliability Standard Audit Worksheet

R2 Supporting Evidence and Documentation

- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
 - 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

Registered Entity Response:

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

DRAFT NERC Reliability Standard Audit Worksheet

Compliance Assessment Approach Specific to CIP-002-6, R2

This section to be completed by the Compliance Enforcement Authority

	Verify the reviews of the identifications in Requirement R1 have occurred at least once every 15 calendar months.
	Verify the approvals by the CIP Senior Manager or delegate of the identifications in Requirement R1 have occurred at least once every 15 calendar months.

Auditor Notes:

DRAFT

Additional Information:

Reliability Standard

The full text of CIP-002-6 may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Standards”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

FERC Order No. 706

FERC Order No. 791

FERC Letter Order dated December 27, 2016, Docket No. RD17-2-000

CIP-002-6 - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

DRAFT NERC Reliability Standard Audit Worksheet

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing

undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.

- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
 - 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
 - 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
-

DRAFT

DRAFT NERC Reliability Standard Audit Worksheet

Revision History for RSAW

Version	Date	Reviewers	Revision Description
DRAFT1v0	09/19/2017	RSAWTF	New document based on CIP-002-5.1a RSAW
DRAFT1v1	10/02/2017	RSAWTF	Changed version from -6a to -6. Changed version date to 10/2/2017. Grammatical change to item 3 of Question 1. Changed "Additional Information," "Reliability Standard" to match NERC web site. Corrected revision date of DRAFT1v0.

DRAFT

Reliability Standard Audit Worksheet¹

CIP-002-~~65.1a~~ — Cyber Security — BES Cyber System Categorization

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X	X	X	X		X			X	X		
R2	X	X	X	X		X			X	X		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.
~~The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.~~

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

DRAFT NERC Reliability Standard Audit Worksheet

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above*.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

* See the full text of CIP-002-~~65-1a~~ for this reference.

Registered Entity Response (Required):

Question 1: Do you share compliance responsibility for this Requirement with another Responsible Entity?

Yes No

For example, is any BES Cyber System located at a shared facility?

If “Yes,” list the following for each asset for which compliance responsibility is shared:

- 1. Asset name or designation.
- 2. Formal agreement or other document describing the shared compliance responsibility, if any.
- 3. Other information regarding the shared compliance responsibility ~~which that~~ may be useful to the audit team in determining the appropriate audit scope and approach for the asset.

Note: A separate spreadsheet or other document may be used to provide all or part of this information. If so, provide the document reference below.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-65.1a, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the Responsible Entity has a process to identify each high impact BES Cyber System, each medium impact BES Cyber System, and each asset that contains a low impact BES Cyber System.
	Verify the above process considers all of the following: <ul style="list-style-type: none"> i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems <u>Remedial Action Schemes</u> that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 of the Standard.
	Verify the Responsible Entity has identified each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset.
	Verify the Responsible Entity has identified each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset.
	Verify the Responsible Entity has identified each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any.

Auditor Notes:

DRAFT

R2 Supporting Evidence and Documentation

- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

Registered Entity Response:

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-~~65.1a~~, R2

This section to be completed by the Compliance Enforcement Authority

	Verify the reviews of the identifications in Requirement R1 have occurred at least once every 15 calendar months.
	Verify the approvals by the CIP Senior Manager or delegate of the identifications in Requirement R1 have occurred at least once every 15 calendar months.

Auditor Notes:

DRAFT

Additional Information:

Reliability Standard

The full text of CIP-002-~~65.1a~~ may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Standards”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

FERC Order No. 706

FERC Order No. 791

FERC Letter Order dated December 27, 2016, Docket No. RD17-2-000

CIP-002-~~65.1a~~ - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing

undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

~~**2.12.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

2.12. Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

- 3.3.** Generation resources.
 - 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
 - 3.5.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
 - 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
-

DRAFT

DRAFT NERC Reliability Standard Audit Worksheet

Revision History for RSAW

Version	Date	Reviewers	Revision Description
DRAFT1v0	09/19/2017 4	RSAWTF	New document based on CIP-002-5.1a RSAW
<u>DRAFT1v1</u>	<u>10/02/2017</u>	<u>RSAWTF</u>	<u>Changed version from -6a to -6.</u> <u>Changed version date to 10/2/2017.</u> <u>Grammatical change to item 3 of Question 1.</u> <u>Changed "Additional Information," "Reliability Standard" to match NERC web site.</u> <u>Corrected revision date of DRAFT1v0.</u>

DRAFT

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See implementation plan for CIP-002-6.

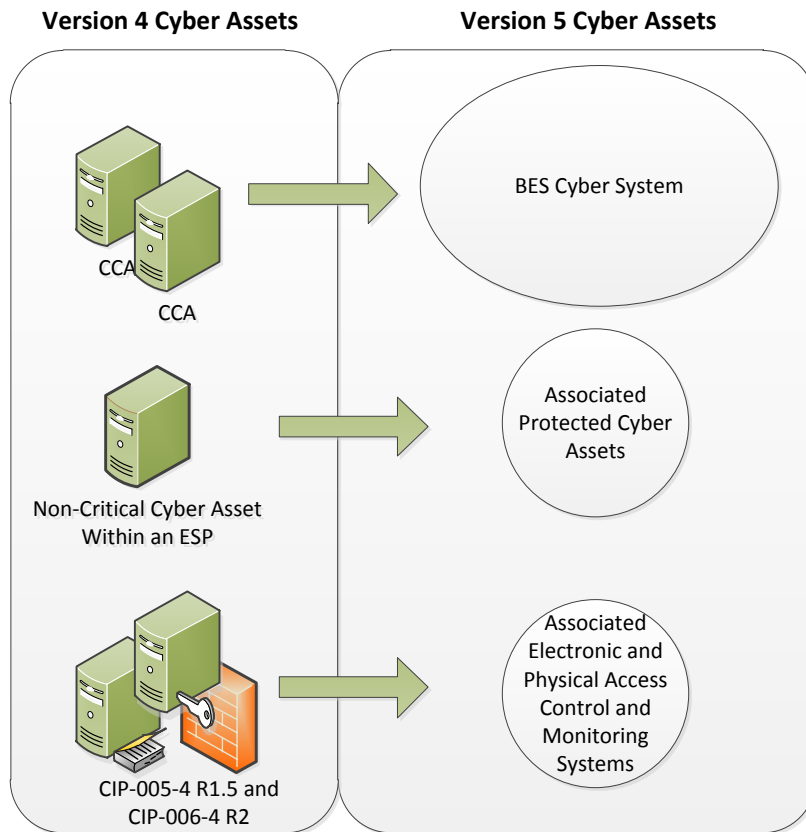
- 6. Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more

implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. During the course of the V5TAG’s activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document¹ to formally recommend that the SDT address these issues during the standards development process and to consider modifications to the standard language.

Among other issues, due to the confusion of the application of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12, and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be evaluated for classification as low impact pursuant to Criterion 3.1.

- 2.12.** Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value"

¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

At NERC's direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO, TOP, GO, GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)

- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a

line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1

year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been

included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300

MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission

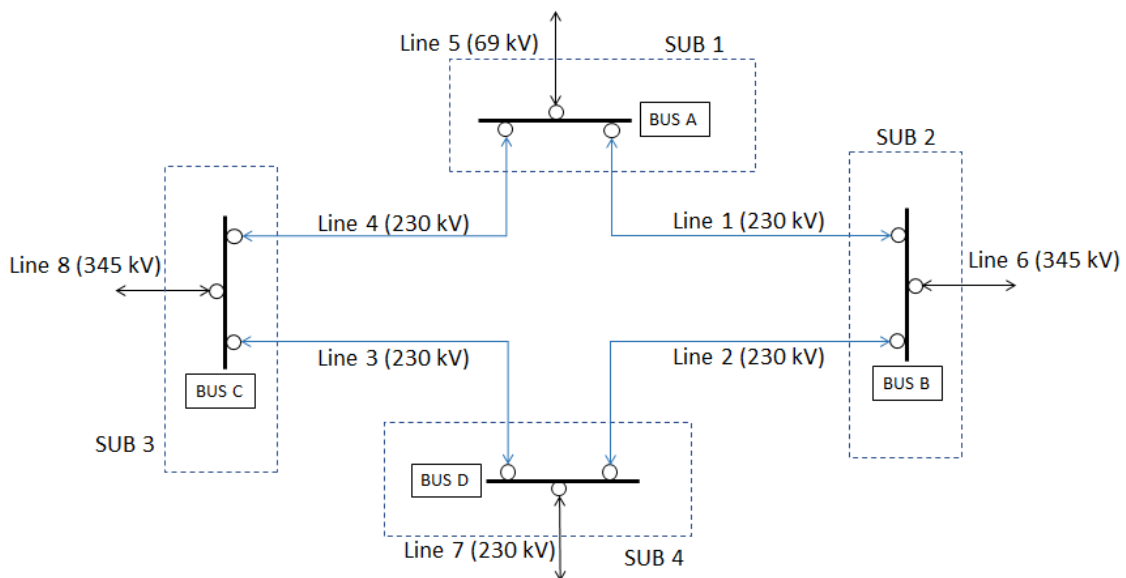
Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line.

Criterion 2.12 Examples:

In example 1 below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

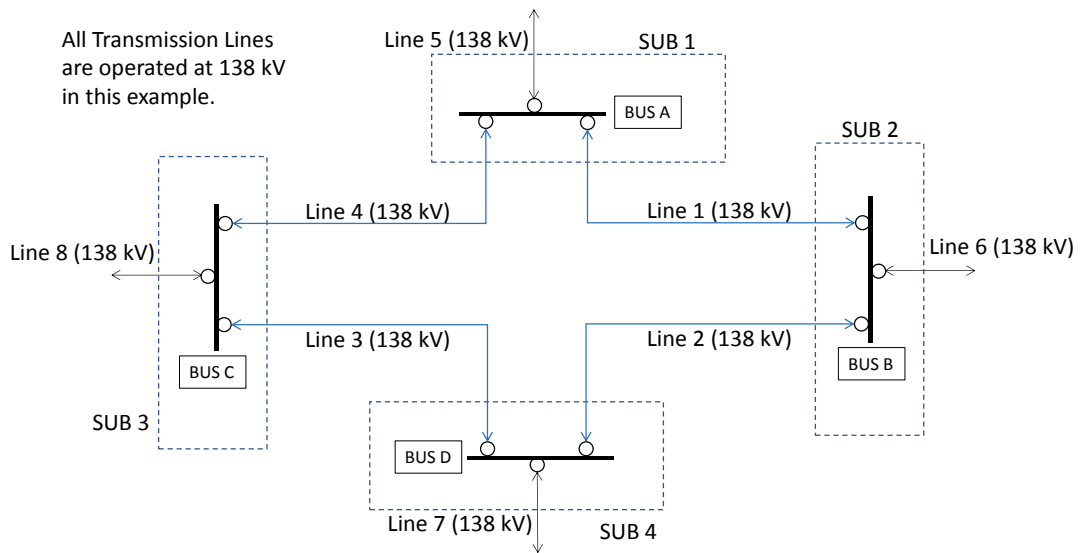
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System associated with the Control Center in this example should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its

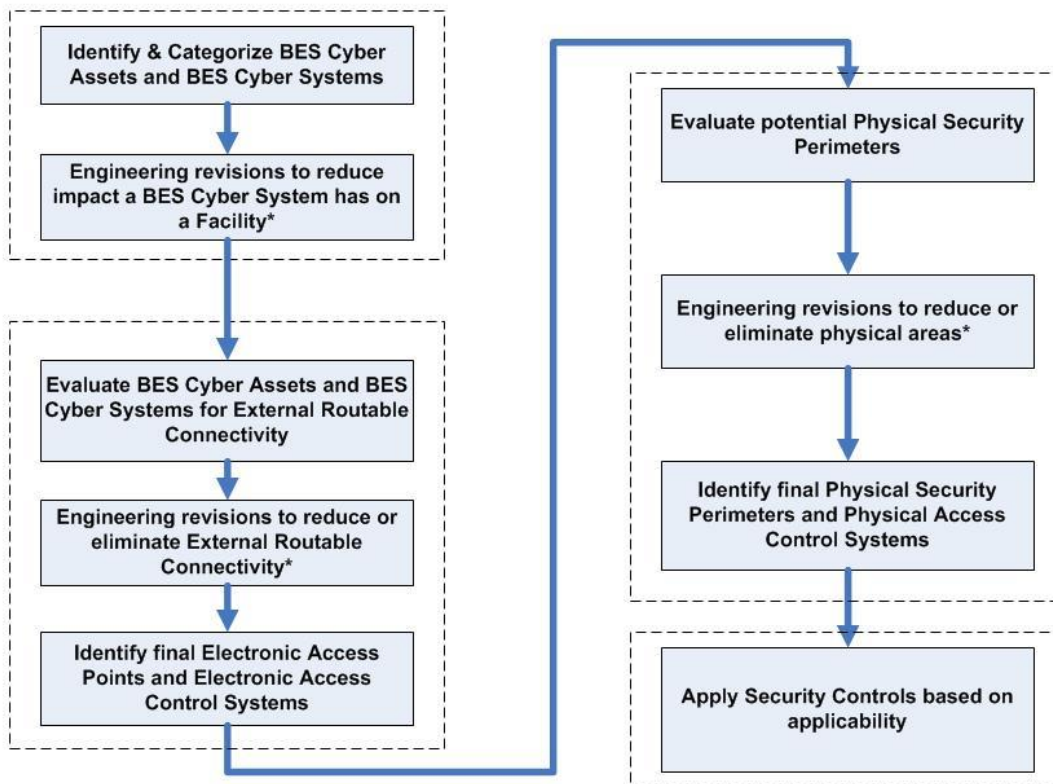
Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator’s Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-~~5.1a6~~
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~4.1.5. Interchange Coordinator or Interchange Authority~~

~~4.1.6.4.1.5. Reliability Coordinator~~

~~4.1.7.4.1.6. Transmission Operator~~

~~4.1.8.4.1.7. Transmission Owner~~

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-~~5.1a6~~:

- 4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
- 4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

~~**5.1 24 Months Minimum** — CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~**5.2** — In those jurisdictions where no regulatory approval is required CIP-002-5.1 shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

See implementation plan for CIP-002-6.

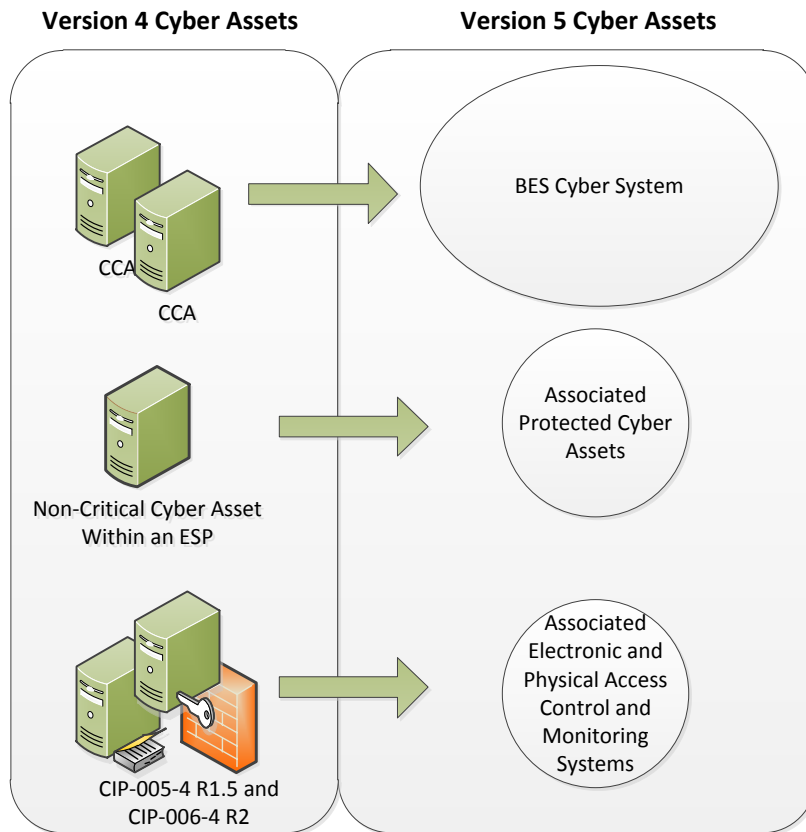
- 6. Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-

developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

E.F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
<u>6</u>	<u>TBD</u>		

Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

~~Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. During the course of the V5TAG’s activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document¹ to formally recommend that the SDT address these issues during the standards development process and to consider modifications to the standard language.

Among other issues, due to the confusion of the application of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12, and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be evaluated for classification as low impact pursuant to Criterion 3.1.

¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

2.12. Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

2.12.2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

At NERC's direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-~~5.1a6~~ and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-~~5.1a6~~. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-~~5.1a6~~

CIP-002-~~5.1a6~~ requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-~~5.1a6~~. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)

- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a

line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-~~5.1a6~~, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of ~~Bas~~BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1

year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.

- Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. ~~there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those ~~Special Protection Systems (SPS), Remedial Action Schemes (RAS),~~ or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a, that monitor and control BES Transmission Operator Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient

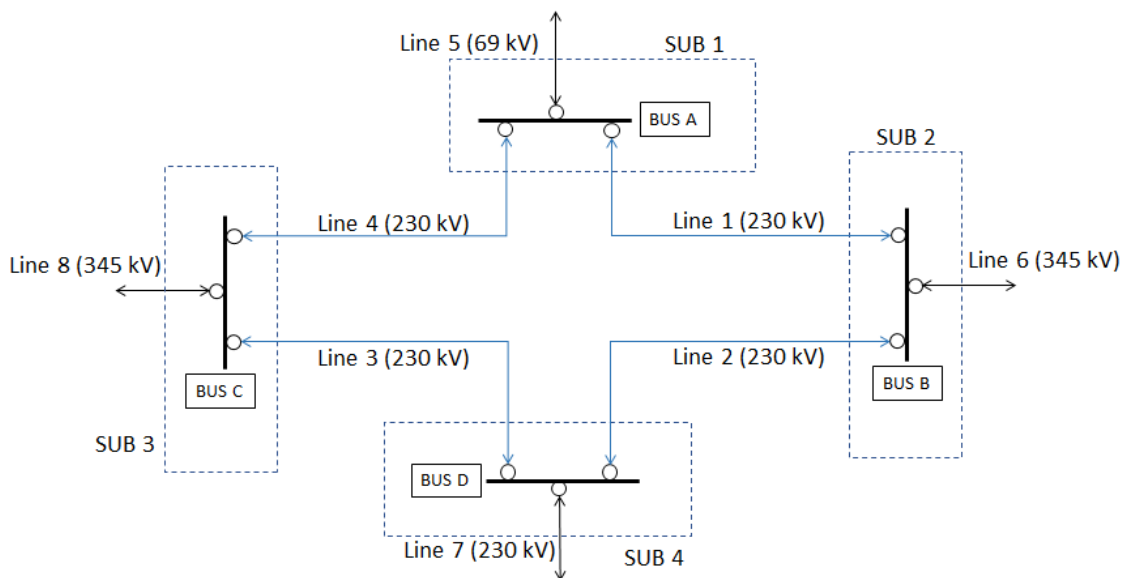
differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line.

Criterion 2.12 Examples:

In example 1 below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with

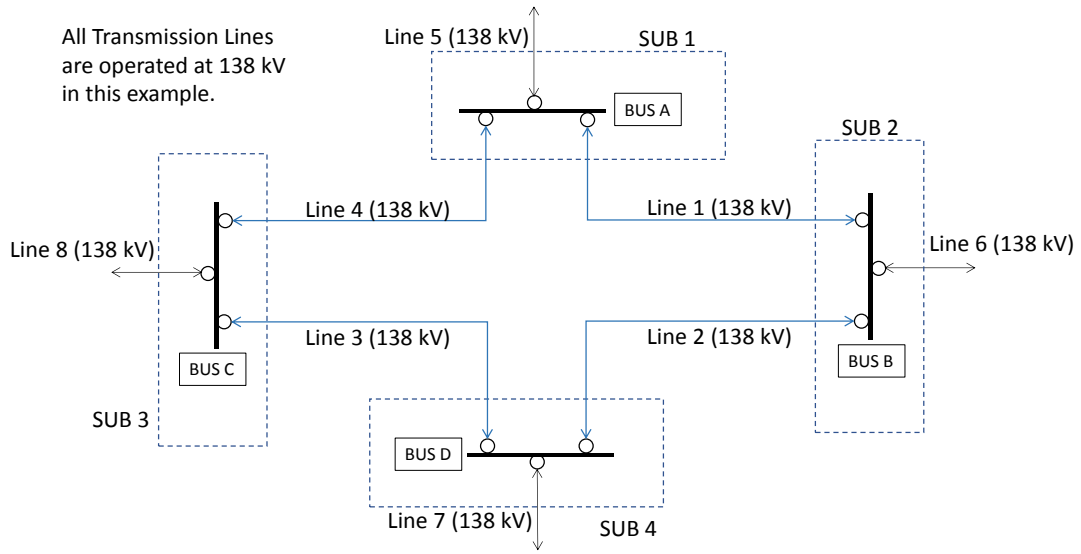
Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>Line 5</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>None</u>	<u>0</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 7</u>	<u>3500</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>Line 6, Line 8</u>	<u>2600</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$$\underline{700+700+700+700+700+1300+1300 = 6100}$$

In the additional example below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System associated with the Control Center in this example should be categorized as high impact, a low impact BES Cyber System pursuant to Criterion 3.1.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>None</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 5, Line 6,</u> <u>Line 7, Line 8</u>	<u>2000</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>None</u>	<u>0</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>None</u>	<u>0</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$$\underline{250+250+250+250+250+250+250+250= 2000}$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator’s restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to

list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

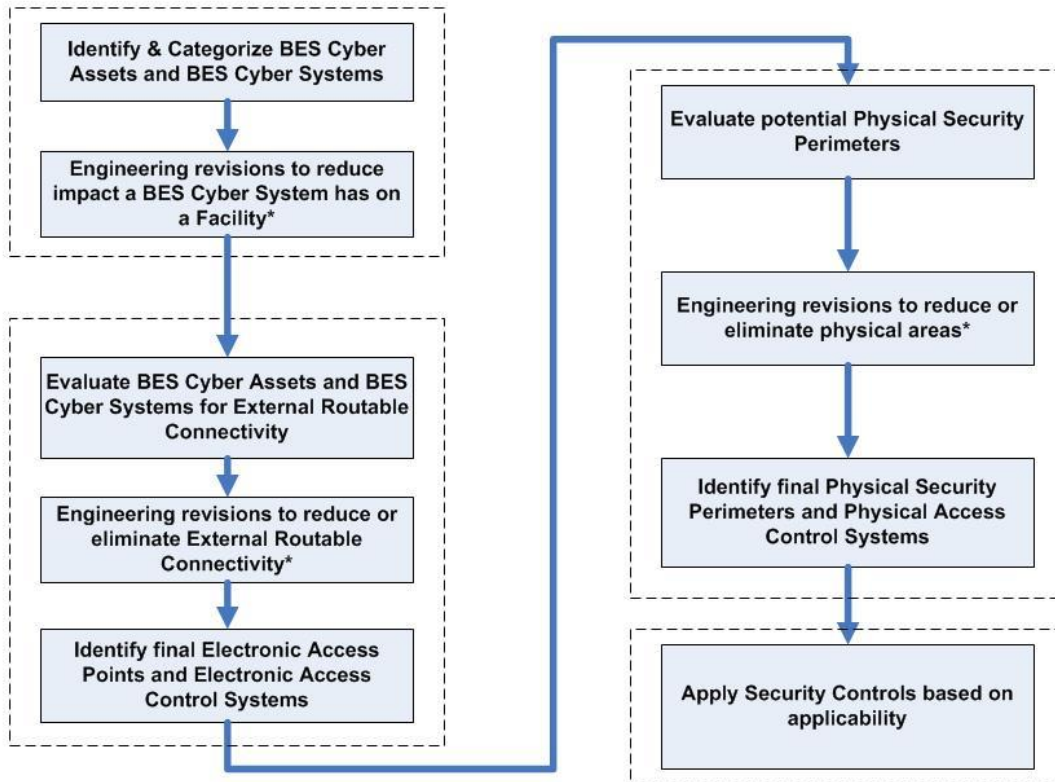
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System*...associated with any of the following [criteria].” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective sixty (60) days following the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned and Unplanned Changes

Planned changes refer to any changes of the electric system or BES Cyber System as identified through the assessment under CIP-002-6, Requirement R2, which were planned and implemented by the responsible entity.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the applicable CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

In contrast, *unplanned* changes refer to any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *planned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System, and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System. For example, initial performance shall be within 15 months following the update of the identification and categorization of the affected BES Cyber System for requirements that must be performed at least once every 15 calendar months.

For *unplanned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System.

Scenario of Unplanned Changes	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months

Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System from low impact BES Cyber System	12 months
Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)	24 months

For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards Transmission Owner (TO) Control Center (TOCC) Performing Transmission Operator (TOP) Obligations, CIP-002-6

Do not use this form for submitting comments. Use the [electronic form](#) to submit comments on **CIP-002-6 – Cyber Security – BES Cyber System Categorization**. The electronic form must be submitted by **8 p.m. Eastern, Monday, October 30, 2017**.

Additional information is available on the [project page](#). If you have questions, contact Standards Developers, [Katherine Street](#) at (404) 446-9702 or [Mat Bunch](#) at (404) 446-9785.

Background Information

The purpose of Project 2016-02 is to (1) address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822 and (2) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document). The V5TAG consisted of representatives from FERC, NERC, Regional Entities and industry stakeholders. It was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. In the course of the V5TAG's activities, it identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the [CIP Version 5 Issues for Standard Drafting Team Consideration](#) document (V5TAG Transfer Document) to formally recommend that the SDT address these issues during the standards development process, and to consider modifications to the standard language.

Among other issues, the V5TAG recommended clarification of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12.

Accordingly, the Project 2016-02 SDT proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements to a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes an average MVA line loading, based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12 and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weight value of lines exceed 6000, the Control Center's associated BES Cyber System(s) must be identified as medium impact. If the aggregate weight value of lines does not exceed 6000, the Control Center's associated BES Cyber System(s) must be evaluated for classification as low impact pursuant to Criterion 3.1.

Guidelines and Technical Basis

At NERC's direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

SDT Approach

The Project 2016-02 SDT proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements for a TO Control Center that performs the functional obligations of a TOP. This proposed criterion establishes a minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines, regardless of a Responsible Entity's functional registration. This allows TOs and TOPs to identify their BES Cyber Systems associated with Control Centers as medium or low impact based on the BES Cyber System's span of control. This contrasts with the currently approved Criterion 2.12, which identifies BES Cyber Systems as medium impact when they are associated with a Control Center or backup Control Center used to perform the functional obligations of the TOP and not included in the high impact rating.

Questions

1. Criterion 2.12: In the V5TAG Transfer Document, the V5TAG requested the SDT to “clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the capability to operate switches, breakers, and relays in the BES.” The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to make this clarification. Do you agree that the revision clarifies the applicability of Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

2. Criterion 2.12: The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to be similar to the construct used in Criterion 2.5. Do you agree with the SDT’s approach in the modified criterion to evaluate a BES Cyber System’s span of control by summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

3. Criterion 2.12: Do you agree with the 6000 aggregate weighted value that is used in Criterion 2.12 to establish the minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control Transmission? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

4. Criterion 2.12: The SDT modified Criterion 2.12 to categorize BES Cyber Systems associated with Control Centers that monitor and control Transmission regardless of a Responsible Entity’s functional registration. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

5. Criterion 2.12: Do you agree with the proposed modifications to Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- Yes
- No

Comments:

6. Implementation Plan: Do you agree with the SDT’s proposed Implementation Plan? If you agree with the proposed implementation time period, please note the actions you will take that require this amount of time to complete. If you think an alternate implementation time period is needed – shorter or longer - please propose an alternate implementation plan and provide a detailed explanation of actions and time needed to meet the implementation deadline.

- Yes
- No

Comments:

7. The SDT considered a number of approaches and determined that proposed CIP-002-6 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for a more cost effective approach that addresses the reliability objective, please provide your recommendation and, if appropriate, technical justification.

- Yes
- No

Comments:

8. If you have additional comments on proposed CIP-002-6, Attachment 1, Criterion 2.12 that you have not provided in response to the questions above, please provide them here.

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	High
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity’s CIP management program.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The VRF is not being modified for this requirement. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity’s CIP management program. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1

Proposed VRF	High
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1

Lower	Moderate	High	Severe
<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high or</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</p>

<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
---	--	---	---

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	
--	---	---	--

VSL Justifications for CIP-002-6 Requirements R1

<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a:</u> The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b:</u> Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.</p>

<p>FERC VSL G4</p> <p>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.</p>
--	--

Project 2016-02 Consideration of Issues and Directives

CIP V5 Issues for Standard Drafting Team Consideration¹

From experience in the CIP Version 5 Transition Study and on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty implementing the requirements. The V5TAG members found that some of the language within the CIP Version 5 standards could be interpreted in more than one way. These interpretations, that could alter the perceived context or intent of the requirements, went beyond acceptable, customary levels of standard language flexibility. To address this, the V5TAG presented the issue to the standard drafting team for its consideration.

The Standard Drafting Team modified Standard CIP-002-6 to address the issue of Transmission Owner (TO) Control Centers performing the functional obligations of the Transmission Operator (TOP).

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.	The Project 2016-02 Standard Drafting Team (SDT) revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 to address all Control Centers and backup Control Centers of Transmission, regardless of registration. The revision provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact. The

¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
	reference to Transmission Operator has been removed to provide clarity.
<p>Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the “CIP-002-5” section paragraph starting with “Responsibility for the reliable operation of the BES is spread across all Entity Registrations”; the table following that paragraph; the “High Impact Rating (H)” section; and the criterion bullets for Control Centers under the “Medium Impact Rating (M)” section.</p>	<p>The revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact. All other BES Cyber Systems associated with Control Centers of Transmission that do not exceed the bright line threshold will be categorized as low impact. Based on this categorization, the requirements applicable to the Control Center’s BES Cyber Systems are clearly defined through the Applicable Systems language throughout Standards CIP-003 through CIP-011.</p>
<p>The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include ‘Control Center’, for example, the revised Glossary term for “System Operator” to be effective July 1, 2016).</p>	<p>The SDT is considering revisions to the definition of Control Center, but asserts that the modifications to Criterion 2.12 of CIP-002-6, Attachment 1, effectively address the concerns raised by the V5TAG regarding Transmission Owner Control Centers.</p>
<p>The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.</p>	<p>The SDT contends that the issue raised by the V5TAG is uniquely associated with small Transmission Owner Control Centers and Transmission Operator Control Centers. Therefore, Reliability Standard CIP-002-5.1a, Attachment 1, Criteria 1.1, 1.2, 1.3, 1.4, 2.11, and 2.13 are sufficiently clear and do not need modification.</p>

Standards Announcement

Reminder

Project 2016-02 Modifications to CIP Standards

Initial Ballot and Non-binding Poll Open through October 30, 2017

[Now Available](#)

An initial ballot for **CIP-002-6 – Cyber Security – BES Cyber System Categorization** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, October 30, 2017**

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) [here](#). If you experience any difficulties in navigating the SBS, contact [Wendy Muller](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact [Katherine Street](#) at (404) 446-9702 or [Mat Bunch](#) at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through **October 30, 2017**
Ballot Pools Forming through **October 13, 2017**

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, October 30, 2017**.

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience any difficulties navigating the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, October 13, 2017**. Registered Ballot Body members can join the ballot pools [here](#).

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS is **not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted October 20-30, 2017.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Senior Standards Developer, [Katherine Street](#) or at (404) 446-9702 or Standards Developer, [Mat Bunch](#) at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through **October 30, 2017**
Ballot Pools Forming through **October 13, 2017**

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, October 30, 2017**.

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience any difficulties navigating the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, October 13, 2017**. Registered Ballot Body members can join the ballot pools [here](#).

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS is **not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted October 20-30, 2017.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Senior Standards Developer, [Katherine Street](#) or at (404) 446-9702 or Standards Developer, [Mat Bunch](#) at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-01 Modifications to CIP Standards

Draft Reliability Standard Audit Worksheet (RSAW) Posted for Industry Comment through October 30, 2017

[Now Available](#)

The draft RSAW for **CIP-002-6 – Cyber Security – BES Cyber System Categorization** is posted on the [project page](#) for industry comment through **8 p.m. Eastern, Monday, October 30, 2017**. Submit feedback regarding the draft RSAW to RSAWfeedback@nerc.net.

For more information or assistance, contact [Katherine Street](#) at (404) 446-9702 or [Mat Bunch](#) at (404) 446-9785.

North American Electric Reliability Corporation

3353 Peachtree Rd, NE

Suite 600, North Tower

Atlanta, GA 30326

404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Comment: [View Comment Results](#)

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 IN 1 ST

Voting Start Date: 10/20/2017 12:01:00 AM

Voting End Date: 10/30/2017 8:00:00 PM

Ballot Type: ST

Ballot Activity: IN

Ballot Series: 1

Total # Votes: 275

Total Ballot Pool: 318

Quorum: 86.48

Weighted Segment Value: 66.78

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	83	1	41	0.631	24	0.369	0	8	10
Segment: 2	7	0.4	4	0.4	0	0	0	3	0
Segment: 3	78	1	36	0.571	27	0.429	0	5	10
Segment: 4	23	1	14	0.737	5	0.263	0	1	3
Segment: 5	68	1	30	0.588	21	0.412	0	6	11
Segment: 6	49	1	20	0.513	19	0.487	0	3	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	6	0.4	4	0.4	0	0	0	2	0
Totals:	318	5.9	150	3.94	96	1.96	0	29	43

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted

5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Third-Party Comments
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments
5	TECO - Tampa Electric Co.	R James Rocha		Negative	Comments Submitted
3	Piedmont EMC	Lawrence Hopkins Jr		None	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers- Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments

				Submitted	
5	PSEG - PSEG Fossil LLC	Tim Kucey	Negative	Third-Party Comments	
1	Network and Security Technologies	Nicholas Lauriat	Affirmative	N/A	
3	WEC Energy Group, Inc.	Thomas Breene	Affirmative	N/A	
1	Puget Sound Energy, Inc.	Theresa Rakowsky	Affirmative	N/A	
5	WEC Energy Group, Inc.	Linda Horn	Affirmative	N/A	
1	Colorado Springs Utilities	Brandon Ware	Negative	Comments Submitted	
6	Seattle City Light	Charles Freeman	Affirmative	N/A	
6	WEC Energy Group, Inc.	Scott Hoggatt	Affirmative	N/A	
3	Seattle City Light	Tuan Tran	Affirmative	N/A	
6	APS - Arizona Public Service Co.	Bobbi Welch	Affirmative	N/A	
1	Salt River Project	Steven Cobb	Negative	Comments Submitted	
5	AEP	Thomas Foltz	Affirmative	N/A	
2	PJM Interconnection, L.L.C.	Mark Holman	Abstain	N/A	
6	Austin Energy	Andrew Gallo	Affirmative	N/A	
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Affirmative	N/A	
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Affirmative	N/A	
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A	
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Affirmative	N/A	
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro	Affirmative	N/A	
3	Silicon Valley Power - City of Santa Clara	Val Ridad	Affirmative	N/A	
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Long Island Power Authority	Robert Ganley	Negative	Third-Party Comments	
5	Seattle City Light	Mike Haynes	Affirmative	N/A	
4	WEC Energy Group, Inc.	Anthony Jankowski	Affirmative	N/A	
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A	
3	Portland General Electric Co.	Angela Gaines	Affirmative	N/A	
5	Puget Sound Energy, Inc.	Eleanor Ewry	Affirmative	N/A	
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Affirmative	N/A	
5	Great River Energy	Preston Walsh	Affirmative	N/A	
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	N/A	
3	Cowlitz County PUD	Russell Noble	Affirmative	N/A	
6	Portland General Electric Co.	Daniel Mason	Affirmative	N/A	
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A	

10	Florida Reliability Coordinating Council	Peter Heidrich		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Negative	Third-Party Comments
5	Acciona Energy North America	George Brown		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Harold Sherrill	Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Abstain	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage		Negative	Comments Submitted
6	Modesto Irrigation District	James McFall		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Abstain	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
4	Seattle City Light	Hao Li		Affirmative	N/A

5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	Duke Energy	Greg Cecil	Colby Bellville	Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Dawn Hamdorf	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Randy Crissman		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	David Weber		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
2	California ISO	Richard Vine		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	KAMO Electric Cooperative	Tony Gott		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments

5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Ellen Oswald		Affirmative	N/A
1	Western Area Power Administration	sean erickson		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A

4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		None	N/A
5	JEA	John Babik		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		None	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
4	LaGen	Richard Comeaux		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
1	Hydro-Quebec TransEnergie	Nicolas Turcotte		Affirmative	N/A

1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	NRG - NRG Energy Power Marketing, Inc.	Rick Keetch		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Negative	Comments Submitted
3	AEP	Aaron Austin		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Martine Blair	Jeff Johnson	Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		None	N/A
3	Intermountain REA	David Maier		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	James Anderson		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A

3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Negative	Comments Submitted
1	Lower Colorado River Authority	Michael Shaw	Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence	None	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak	Abstain	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams	Abstain	N/A
6	Santee Cooper	Michael Brown	Abstain	N/A
3	Santee Cooper	James Poston	Abstain	N/A
5	Santee Cooper	Tommy Curtis	Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell	Abstain	N/A
3	Salt River Project	Rudy Navarro	Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
4	National Rural Electric Cooperative Association	Barry Lawson	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	None	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
1	Peak Reliability	Scott Downey	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	None	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative	N/A

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 Non-binding Poll IN 1 NB

Voting Start Date: 10/20/2017 12:01:00 AM

Voting End Date: 10/30/2017 8:00:00 PM

Ballot Type: NB

Ballot Activity: IN

Ballot Series: 1

Total # Votes: 241

Total Ballot Pool: 285

Quorum: 84.56

Weighted Segment Value: 65.08

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	34	0.723	13	0.277	14	12
Segment: 2	7	0.2	2	0.2	0	0	5	0
Segment: 3	71	1	32	0.64	18	0.36	12	9
Segment: 4	19	1	11	0.733	4	0.267	1	3
Segment: 5	61	1	22	0.564	17	0.436	11	11
Segment: 6	44	1	16	0.533	14	0.467	7	7
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	1	0
Segment: 9	1	0	0	0	0	0	0	1

Segment:	6	0.5	5	0.5	0	0	1	0
Totals:	285	5.8	123	3.994	66	1.806	52	44

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A

5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Negative	Comments Submitted
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

1	Colorado Springs Utilities	Brandon Ware		Negative	Comments Submitted
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Acciona Energy North America	George Brown		None	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A

1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Harold Sherrill	Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Abstain	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Abstain	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	Duke Energy	Greg Cecil	Colby Bellville	Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Dawn Hamdorf	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A

Comments

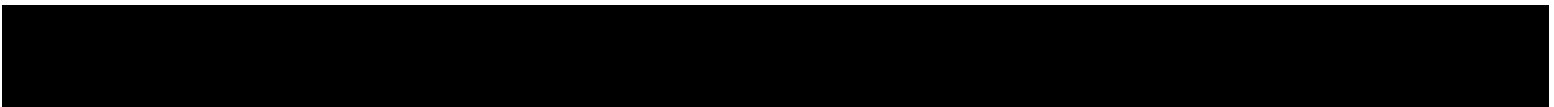
3	Colorado Springs Utilities	Hillary Dobson		Negative	Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Randy Crissman		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	David Weber		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Affirmative	N/A

4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
2	California ISO	Richard Vine		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Abstain	N/A
1	Western Area Power Administration	sean erickson		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted

1	Lakeland Electric	Larry Watt		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Duncel		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		None	N/A
5	JEA	John Babik		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		None	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A

5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	NRG - NRG Energy Power Marketing, Inc.	Rick Keetch		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	AEP	Aaron Austin		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipp		None	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas	Jeff Johnson	None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak	Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley	Abstain	N/A
1	Santee Cooper	Shawn Abrams	Abstain	N/A
6	Santee Cooper	Michael Brown	Abstain	N/A
3	Santee Cooper	James Poston	Abstain	N/A
5	Santee Cooper	Tommy Curtis	Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell	Abstain	N/A
3	Salt River Project	Rudy Navarro	Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	None	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
1	Peak Reliability	Michael Granath	None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	None	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A



Comment Report

Project Name: 2016-02 Modifications to CIP Standards | CIP-002-6
Comment Period Start Date: 9/14/2017
Comment Period End Date: 10/30/2017
Associated Ballots: 2016-02 Modifications to CIP Standards CIP-002-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 192 different people from approximately 129 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

- 1. Criterion 2.12:** In the V5TAG Transfer Document, the V5TAG requested the SDT to “clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the capability to operate switches, breakers, and relays in the BES.” The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to make this clarification. Do you agree that the revision clarifies the applicability of Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- 2. Criterion 2.12:** The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to be similar to the construct used in Criterion 2.5. Do you agree with the SDT’s approach in the modified criterion to evaluate a BES Cyber System’s span of control by summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls? If not, please provide your rationale and an alternate proposal.

- 3. Criterion 2.12:** Do you agree with the 6000 aggregate weighted value that is used in Criterion 2.12 to establish the minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control Transmission? If not, please provide your rationale and an alternate proposal.

- 4. Criterion 2.12:** The SDT modified Criterion 2.12 to categorize BES Cyber Systems associated with Control Centers that monitor and control Transmission regardless of a Responsible Entity’s functional registration. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

- 5. Criterion 2.12:** Do you agree with the proposed modifications to Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- 6. Implementation Plan:** Do you agree with the SDT’s proposed Implementation Plan? If you agree with the proposed implementation time period, please note the actions you will take that require this amount of time to complete. If you think an alternate implementation time period is needed – shorter or longer - please propose an alternate implementation plan and provide a detailed explanation of actions and time needed to meet the implementation deadline.

- 7. The SDT considered a number of approaches and determined that proposed CIP-002-6 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for a more cost effective approach that addresses the reliability objective, please provide your recommendation and, if appropriate, technical justification.**

- 8. If you have additional comments on proposed CIP-002-6, Attachment 1, Criterion 2.12 that you have not provided in response to the questions above, please provide them here.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	3	RF	FirstEnergy Corporation	Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Southern Company - Southern Company Services, Inc.	Brandon Cain	1,3,5,6	FRCC,MRO,NPCC,SERC,SPP RE,Texas RE,WECC	Southern Company	Katherine Prewitt	Southern Company - Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company - Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company - Southern Company Generation and Energy Marketing	6	SERC
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC

					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Colby Bellville	Colby Bellville		FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO

					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
SRC	David Francis	2,3	FRCC,MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC + SWG	Gregory Campoli	New York Independent System Operator	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Terry Bilke	Midcontinent ISO, Inc.	2	RF
					Elizabeth Axson	Electric Reliability Council of Texas, Inc.	2,3	Texas RE
					Ben Li	IESO	1	MRO
					Drew Bonser	SWG	NA - Not Applicable	NA - Not Applicable
					Darrem Lamb	CAISO	2	WECC
					Matt Goldberg	ISONE	2	NPCC
Associated Electric Cooperative, Inc.	Mark Riley	1		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC

Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
Ted Hilmes	KAMO Electric Cooperative	3	SERC
Walter Kenyon	KAMO Electric Cooperative	1	SERC
Stephen Pogue	M and A Electric Power Cooperative	3	SERC
William Price	M and A Electric Power Cooperative	1	SERC
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
John Stickley	NW Electric Power Cooperative, Inc.	3	SERC

					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Seattle City Light	Paul Haase	1,3,4,5,6	WECC	Seattle City Light	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Bud Freeman	Seattle City Light	6	WECC
					Paul Haase	Seattle City Light	1,3,4,5,6	WECC
					Ginette Lacasse	Seattle City Light	1,3,4,5,6	WECC
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC

Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Greg Campoli	NYISO	2	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Helen Lainis	IESO	2	NPCC
Chantal Mazza	Hydro Quebec	2	NPCC
Michael Forte	Con Ed	1	NPCC
Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

					Brian O'Boyle	Con Ed	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Colorado Springs Utilities	Shannon Fair	6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Megan Wagner	Westar Energy	6	SPP RE
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
PSEG	Sheranee Nedd	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF
					Karla Jara	PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF

					Joseph Smith	PSEG - Public Service Electric and Gas Co	1	RF
--	--	--	--	--	--------------	---	---	----

1. Criterion 2.12: In the V5TAG Transfer Document, the V5TAG requested the SDT to “clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the capability to operate switches, breakers, and relays in the BES.” The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to make this clarification. Do you agree that the revision clarifies the applicability of Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer No

Document Name

Comment

We believe further language is specifically required in Criterion 2.12 to clarify that the functional registration of Transmission Owner and Transmission Operator apply. Per the registration criteria, Transmission Operators are “responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.” As a result, this responsibility falls on directly on Transmission Operators. Further expansion of the criterion places responsibilities on Transmission Owners for activities they are not registered for.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, Dominion Energy suggests that the language be changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer	No
Document Name	
Comment	
<p>No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
<p>Although the operation of breakers and switches is discussed in the Supplemental Material, it is not clear how Criterion 2.12 addresses whether “the TO has the capability to operate switches, breakers, and relays in the BES.”</p> <p>CIP-002 is fundamental to determining which Cyber Assets are within scope. Reclamation recommends the impact rating of a BES Cyber System be determined by its possible impact on the Bulk Electric System, not where it resides (Control Center or any other location), how it is identified (virtual, non-virtual, hardware, software, etc.), and regardless of a Responsible Entity’s functional registration. Following this principle, phrases such as “performing the functional obligations of” are unnecessary.</p> <p>Reclamation also recommends simplifying the Impact Rating Criteria using the methodology described below.</p> <p>BES Cyber Systems are to be rated as high, medium, or low impact as follows:</p> <p>A high impact BES Cyber System has one or more of the following characteristics:</p> <ul style="list-style-type: none"> • Is used to operate transmission lines of 500kV or above • Supports a sum greater than 2500kV of transmission lines above 230kV • Supports generation with an aggregate capacity greater than 3000MW • Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact <p>A medium impact BES Cyber System has one or more of the following characteristics:</p> <ul style="list-style-type: none"> • Supports generation with the aggregate capacity between 1500 – 3000MW • Supports a sum between 1500 – 2500kV of transmission lines above 230kV • Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more 	

A low impact BES Cyber System has one or more of the following characteristics:

- Supports a sum less than 1500kV of transmission lines above 230kV
- Supports transmission only between 110 – 230kV
- Supports generation with an aggregate capacity between 75 – 1500MW
- Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System
- Supports any Facilities that are designated a blackstart resource
- Supports any other RAS not already identified as a medium impact BES Cyber System

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that "[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be changed to "In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s)." Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center."

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name

Comment

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be

changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer

No

Document Name

Comment

The removal of the term “functional obligation” from 2.12 still does not clarify the requirement applies to TO because the capitalized term Control Center is used and that term implies functional registry (RC/BA/TOP/GOP). Clarification could be improved by using the non-capitalized term “control center” and defined as used in CIP-014. In addition, the use of the term “control” is also a source of confusion as it can be interpreted as having operational control (ie. Direct the switching operation) or physical control (perform the switching operation).

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy requests further clarification on the removal of the phrase “perform functional obligations of a TOP”. Was it the drafting team's intent that all Control Centers, and not just Control Centers that perform TOP obligations, should be considered applicable to the new criterion? For instance, would a Control Center operated by a GO/GOP or a DP be considered under this criterion, even though any operation involving Transmission lines conducted by that Control Center, would only be done at the direction of a Transmission Operator? We would also like to point out that the use of “functional obligations” is also present when referencing the BA in 2.13. Lastly, the revision proposed to criterion 2.12 appears to create some inconsistency with the language used in the High Impact section, part 1.3.

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMMPA

Answer

No

Document Name

2016-02_CIP-002-6_Unofficial_Comment_Form_10 27 17 draft- FMMPA.pdf

Comment

FMMPA appreciates the SDT efforts for clarifying the the applicability requirements for a TO Control Center that performs the functional obligations of a TOP. We have some suggested language for Criterion 2.12 that we feel removes some ambiguity and possible interpretation questions. Our suggested language is as follows:

“Each BES Cyber System, not included in Section 1 above, associated with any of the following:”

“Cyber Assets used to control BES Transmission lines, located at Control Centers or backup Control Centers, where the summed weighted value (according to the table below) of each BES Transmission Line controlled or monitored exceeds 6000.”

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).” EEI is concerned that this statement might be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the SDT consider revised language similar to the following: “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 1 response.

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer No

Document Name

Comment

The new 2.12 criterion language has the Impact Rating on the "Control Center" as an asset, yet in the "Rationale for Criterion 2.12" on page 18 of the standard it has the "...aggregate weighted value for applicable BES Cyber Systems...". This is a problem because there could be a case where the number of transmission lines being controlled from a Control Center (asset) add up to a weighted value 8000 but there are two completely separate control systems (applicable BES Cyber Systems) each controlling transmission lines that would add up to a weighted value of 4000. In this case the language of IRC would lead you to make both control systems Medium Impact as the asset is being rated. If the intent of the standard is to assign the aggregate weighted value to the BES Cyber Systems as the language in the "Rationale for Criterion 2.12", the two do not align and confuse the reader. The "Consideration of Issues and Directives" on the NERC project site also says that the "Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact.". This leads the reader to believe the aggregate weighted value is associated with BES Cyber Systems, not the Control Center asset itself. We recommend the language of the standard and any rationale or guidance be made clear as to which one (the Control Center asset or the BES Cyber System) the aggregate weighted value is associated.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

We support comments offered by EEI for this question.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer

Yes

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer Yes

Document Name

Comment

MidAmerica would like to change its answer for this question to NO.

MidAmerican agrees with EEI's comments. Please see EEI's Comments below:

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer Yes

Document Name

Comment

NRECA supports the modified Criterion 2.12.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Salt River Project supports comments submitted by APPA.	
Likes 0	
Dislikes 0	
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
MMWEC agrees that revisions to Criterion 2.12 clarify the issue of "functional obligation." However, additional wording for Criterion 2.12 is needed to further clarify how Criterion 2.12 is to be applied. MMWEC supports APPA's response to question 5 regarding this issue.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response**Rachel Coyne - Texas Reliability Entity, Inc. - 10**

Answer

Yes

Document Name

Comment

Texas RE agrees with the Standard Drafting Team's (SDT) approach to to replace the "functional obligation" language in CIP-002-5.1, Criteria 2.12 with a bright line 6000 weighted value for BES Transmission Line threshold for delineating Medium and Low Impact Control Centers.

Likes 0

Dislikes 0

Response**Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light**

Answer

Yes

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response**Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group**

Answer

Yes

Document Name

Comment

The group would like the drafting team to provide clarity on page 18 in reference to criteria 2-12 rationale. The third paragraph mention BES Cyber Systems and we feel that it should reference BES Transmission Lines instead.

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Yes

Document Name

Comment

SNPD does not have comments on Question 1.

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

NRG requests that the drafting team to provide clarity on page 18 in reference to criteria 2-12 rationale. The third paragraph mentions BES Cyber Systems and NRG requests SDT consideration that it should reference BES Transmission Lines instead.

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Maier - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Bette White - AES - Indianapolis Power and Light Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3

Answer Yes

Document Name

Comment

Likes 1 Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECl & Member G&Ts

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

2. Criterion 2.12: The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to be similar to the construct used in Criterion 2.5. Do you agree with the SDT's approach in the modified criterion to evaluate a BES Cyber System's span of control by summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls? If not, please provide your rationale and an alternate proposal.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer No

Document Name

Comment

Evaluation should be based on the short circuit MVA capacity at the element location in the system.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

We believe the control center should have the same rating as the highest impact rating of the transmission facilities that it monitors. Example, if a control center monitors high impact transmission facilities, then it should also have a high impact rating. If a control center monitors only low or medium impact transmission facilities, then it should also have a low or medium impact rating, respectively.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 2 response.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

EEI cannot support the modified criterion and weighted value used in Criterion 2.12 at this time for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. *(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)*
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

For these reasons, EEI asks the SDT to consider other approaches such as limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” Contained within this recommendation is a suggestion that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we suggest that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

We submit that the above recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The

rational for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes 1

PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

No

Document Name

Comment

The formulation of the question #2 in the answer form is incorrect by inducing the notion of BCS whereas criterion 2.12 of the standard does not mention it. In our view, including the notion of BCS in the determination of the BES transmission lines to be included in the weighted voltage level calculation with a threshold of 6000 would allow an arbitrary division of an entity that would like to subtract from the requirement. We believe that criterion 2.12 as written in version 6 is correct and that the question of the form should be reworded in this way or at least that the respondent indicates No and specifies its answer in the comment section of the question # 2.

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

No

Document Name

Comment

Not all entities controlling lower voltage transmission, which ultimately serve a large customer population, should be allowed to move from medium to low impact for their control centers. Under the proposed criteria, INDN which provides utility services to over 100,000 residents would go from a medium to low impact control center. The low impact CIP requirements are not adequate protections for some entities.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name	
Comment	
<p>MEC disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:</p> <ol style="list-style-type: none"> 1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection. 2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. <i>(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)</i> 3. The proposed Criterion 2.12 does not consider or exempt radial feeders. <p>For these reasons, MEC recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.</p> <p>Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.</p>	
Likes	0
Dislikes	0
Response	
<p>Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3</p>	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"

EEI disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rational and appears to be an arbitrary selection.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. *(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)*
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

For these reasons, EEI recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.”

Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla
---------	---

Dislikes 0	
------------	--

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	No
--------	----

Document Name	
---------------	--

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the methodology described in the response to Question 1.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer	No
--------	----

Document Name	
---------------	--

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer

No

Document Name

Comment

Dominion Energy disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection. There is no methodology provided that demonstrates how the value is derived.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), appears to focus on the number of lines rather than facility impacts. This appears to create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

Dominion Energy recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and in addition to providing the methodology for the derivation of the value, replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

These recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
<p>NRG has a concern that there may be confusion on what the drafting team’s intent is in reference to proposed language pertaining to BES Cyber System’s span of control instead of the BES Cyber System monitors and controls. Industry interpretation of the current language leads NRG stakeholders to believe that the Rationale information may not match up correctly with the CIP-002-6 Standard. (NRG requests clarity on the operation authority versus capability). NRG requests that the drafting team provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.</p> <p>Question: Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element? Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations? It seems that most if not all TOPs are Medium and this can reduce them to Low which may be a concern for the industry.</p>	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
<p>SNPD agrees with the SDT’s approach in using the “aggregated weighted values” per line and per voltage class to determine the Impact Ratings of Control Centers and Backup Control Centers.</p> <p>When the aggregated weighted value of lines for each of the applicable voltage classes exceeds 6000 points, both the Control Center and the Backup Control Center whose Facilities are rated Medium Facilities, and all BES Cyber Systems that are part of the Control Centers should also be rated Medium Impact by association. However, the new terminology, that was adopted by the SDT, “BES Cyber System’s Span of Control”, is somewhat ambiguous. Is this concept related to evaluating the applicability of the BES Reliability Operating Services (BROS)?</p>	

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

The SPP Standards Review Group has a concern that there is confusion on what the drafting team's intent is in reference to proposed language pertaining to BES Cyber System's span of control instead of the BES Cyber System monitors and controls. Our interpretation of the current language leads us to believe that the Rationale information doesn't match up correctly with the CIP-002-6 Standard. (need clarity on the operation authority versus capability). We would ask the drafting team to provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.

Question:

Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element?

Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations?

It seems that most if not all TOP are Medium and this can reduce them to Low. This is a concern.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECl & Member G&Ts

Answer

Yes

Document Name

Comment

The term Transmission Line as defined in the Glossary of Terms Used in NERC Reliability Standards does not adequately identify the endpoints of a Transmission Line. Does the Transmission Line begin and end at the circuit breaker, line switch, or at the bus? A clarification of this issue would help Responsible Entities determine how to count lines in certain configurations, such as tapped lines. Additionally, are Responsible Entities required to count a Transmission Line if they only control the breakers on one end of the line, such as a tie line with a neighboring TOP?

Likes 0

Dislikes 0

Response	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	Yes
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	
Likes	0
Dislikes	0
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	
Likes	0
Dislikes	0
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	
<p>APPA agrees that SDT's approach of "summing the weight value of each BES Transmission Lines that the BES Cyber System monitors and controls" is the desired approach. However, this is not what Criterion 2.12 requires (see answer to question 5 below). As written, Criterion 2.12 sums the BES Transmission Lines that the Control Center monitors and controls.</p>	
Likes	5
Dislikes	0
Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long	

Response

David Gordon - Massachusetts Municipal Wholesale Electric Company - 5

Answer Yes

Document Name

Comment

MMWEC supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3**Answer** Yes**Document Name****Comment**

Agree with the weighting concept however, consider the following:

1. Assuming wording became specific to TOs, should there be a caveat noting the transmission Facilities need to be at two or more locations similar to the existing Control Center definition with respect to TOP? This would exclude TOs that operate one large station.
2. Assuming wording became specific to TOs there should be a weighting for 500 KV and above. Criterion 1.3 would apply to Control Center (TOP registration) that control 500 kV+ lines (criterion 2.4); if 2.12 were specific to TOs, then a weight should be given to the 500 kV+ lines. If the intention is for a TO's control center that "operates" a 500 kV+ facility to be High impact, then clarification is needed in criterion 1.3; if the intention is that TO control centers would, at most, be classified as Medium impact, then a weighting is needed for the 500 kV+ lines in criterion 2.12.

Likes 0

Dislikes 0

Response**Barry Lawson - National Rural Electric Cooperative Association - 4****Answer** Yes**Document Name****Comment**

NRECA supports weighted value approach in the modified Criterion 2.12.

Likes 0

Dislikes 0

Response**Russell Noble - Cowlitz County PUD - 3****Answer** Yes**Document Name****Comment**

Cowlitz PUD agrees with the intent of the SDT as implied in Question 2. However, as written, Criterion 2.12 appears to require an evaluation of the Control Center's span of control rather than the BES Cyber System associated with the Control Center. Please see response to Question 5.

Likes	5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes	0	
Response		
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham		
Answer	Yes	
Document Name		
Comment		
<p>MidAmerica would like to change its answer for this question to NO.</p> <p>MidAmerican agrees with EEI's comments. Please see EEI's Comments below:</p> <p>EEI disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:</p> <ol style="list-style-type: none"> 1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection. 2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. <i>(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)</i> 3. The proposed Criterion 2.12 does not consider or exempt radial feeders. <p>For these reasons, EEI recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value "exceeding 6000" with a range "exceeding 2500 but below 3000." We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.</p> <p>Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower "aggregate weighted value." Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.</p>		
Likes	0	

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer Yes

Document Name

Comment

Colorado Srings Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

N&ST assumes, based on the precise wording of Criterion 2.12, that what must be evaluated is a *Control Center's* span of control, vs. any particular BES Cyber System associated with a Control Center, and that if a Control Center meets this criterion, *all* of its associated BES Cyber Systems must be categorized as medium impact.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Yes

Document Name

Comment

Seminole agrees that this is a valid approach as long as Functional Registrations are honored.

Likes 0

Dislikes 0

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer Yes

Document Name

Comment

Likes 1 Manitoba Hydro , 5, Xiao Yuguang

Dislikes 0

Response

David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG

Answer Yes

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Maier - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer Yes

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response	
Mary Ann Todd - Illinois Municipal Electric Agency - 4	
Answer	
Document Name	
Comment	
IMEA supports APPA comments.	
Likes 0	
Dislikes 0	
Response	

3. Criterion 2.12: Do you agree with the 6000 aggregate weighted value that is used in Criterion 2.12 to establish the minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control Transmission? If not, please provide your rationale and an alternate proposal.

Jim Nail - City of Independence, Power and Light Department - 5

Answer No

Document Name

Comment

As written, there will be TOP Control Centers that will drop from Medium to Low and become exempt from many of the current requirements. Given the propensity for NOT maintaining standards of performance which are not enforced/required, this WILL produce a predictable weakening of the BES's overall Cyber-Security posture.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

Dominion Energy does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4

Answer

No

Document Name

Comment

Tacoma Power proposes that the aggregate weighted value be 30000 instead of 6000. The proposed weighting values overestimates the impact of 115 kV subtransmission networks. For example, between two of our major substations we have a line rated at 239 MW with 4 intermediate looped through distributions stations. In the proposed evaluation methodology each of the short sections between substations would be weighted as 250 for a total value of 1250, overstating the importance of the line by more than a factor of 5.

An alternative to adjusting the threshold would be to exclude any line that terminates at a substation that only has two transmission lines connected.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

No

Document Name

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the methodology described in the response to Question 1.

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	
Comment	
<p>NIPSCO is in support of the comment provided by EEI below.</p> <p>"EEI does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2."</p>	
Likes	0
Dislikes	0
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0
Dislikes	0
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p>	

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer

No

Document Name

Comment

Suggest 3000 points to be in-line with Criterion 2.5. Concerns that entities with large amounts of 100-199kV lines would be excluded (6000 points = 24 100kV lines).

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name

Comment

MEC does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

No

Document Name

Comment

The aggregate weighted value of 6000 is too high for entities controlling lower voltage transmission ultimately serving a large customer population. Under the proposed criteria, INDN which provides utility services to over 100,000 residents would go from a medium to low impact control center. The low impact CIP requirements are not adequate protections for some entities.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

EI cannot support the 6000 aggregate weighted value used in Criterion 2.12 at this time for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 3 response.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

No

Document Name

Comment

See the response to question 2 above.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer

Yes

Document Name

Comment

Co lorado Srings Utilitiessupports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3

Answer Yes

Document Name

Comment

Cowlitz PUD agrees the aggregated weighted value will properly identify the impact threshold of a BES Cyber System as long as the calculated *value* relates directly to those Transmission Lines the BES Cyber System *monitors and controls*.

Likes 5

Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer Yes

Document Name

Comment

NRECA supports the 6000 aggregate weighted value used in Criterion 2.12.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer Yes

Document Name

Comment

Agree with the weighting concept however, consider the following:

1. Assuming wording became specific to TOs, should there be a caveat noting the transmission Facilities need to be at two or more locations similar to the existing Control Center definition with respect to TOP? This would exclude TOs that operate one large station.

2. Assuming wording became specific to TOs there should be a weighting for 500 KV and above. Criterion 1.3 would apply to Control Center (TOP registration) that control 500 kV+ lines (criterion 2.4); if 2.12 were specific to TOs, then a weight should be given to the 500 kV+ lines. If the intention is for a TO's control center that "operates" a 500 kV+ facility to be High impact, then clarification is needed in criterion 1.3; if the intention is that TO control centers would, at most, be classified as Medium impact, then a weighting is needed for the 500 kV+ lines in criterion 2.12.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer

Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer

Yes

Document Name

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer

Yes

Document Name

Comment

Does Criterion 2.12 allow a Responsible Entity to mitigate risk to the BES by separating it's monitoring and control functions at a Control Center into multiple separate BES Cyber Systems? For example, a Responsible Entity monitors and controls Transmission Lines that sum to an aggregate weighted value of 7000, but they split the monitoring and control functions between two BES Cyber Systems (3500 each) that reside in two separate ESPs. This option reduces the risk to the reliability of the BES if a system is compromised. Does this allow the BES Cyber Systems associated with the Control Center in this example to be categorized as low impact BES Cyber Systems?

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Yes

Document Name

Comment

SNPD does not have comments on Question 3.

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Maier - Intermountain REA - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment	
---------	--

Likes	0
-------	---

Dislikes	0
----------	---

Response	
----------	--

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment	
---------	--

Likes	0
-------	---

Dislikes	0
----------	---

Response	
----------	--

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment	
---------	--

Likes	0
-------	---

Dislikes	0
----------	---

Response	
----------	--

Bette White - AES - Indianapolis Power and Light Co. - 3

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment	
---------	--

Likes 0

Dislikes 0

Response

David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer

Yes

Document Name

Comment

Likes 1

Manitoba Hydro , 5, Xiao Yuguang

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Gordon - Massachusetts Municipal Wholesale Electric Company - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jack Cashin - American Public Power Association - 4**Answer** Yes**Document Name****Comment**

Likes 1

Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response**Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Payam Farahbakhsh - Hydro One Networks, Inc. - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Document Name

Comment

MidAmerica would like to change its answer for this question to NO.

MidAmerican agrees with EEI's comments. Please see EEI's Comments below:

EEI does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

The SDT elected to double weighted value used to define Medium Impact substations in Criterion 2.5. While this may be a reasonable approach, the Texas RE requests the SDT provide a basis for this approach, including why the Control Center weighted value bright line should be higher than that used for the Transmission Facility criterion set forth in 2.5. In addition, Texas RE requests clarification on how double circuits are calculated as it is assumed they are calculated as a single line.

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

4. Criterion 2.12: The SDT modified Criterion 2.12 to categorize BES Cyber Systems associated with Control Centers that monitor and control Transmission regardless of a Responsible Entity’s functional registration. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer No

Document Name

Comment

SNPD suggests that a Control Center that is only responsible for Low Impact Facilities, should default to a Low Impact Control Center rating; independent of its registration or weighted value criterion. Currently, there are numerous Medium Impact Control Centers that meet the registration requirements or proposed weighting criteria, but clearly do not have BES Cyber Assets.

“A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non -o adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.”

Registered Entities have identified SCADA related assets and systems as BCS and BCAs in order to comply with Reliability Standards interpretations and the expectations of the regulators. However, if these assets were rendered unavailable, degraded, or misused, they would not adversely impact the Bulk Electric System. In these cases the scope of the impact would be local load service and restoration efforts. They would not result in BES cascading events. The original intent of the NERC Reliability Standards were to address BES reliability, yet the application of Medium Impact Control Centers operating Low Impact Facilities often targets local load service and distribution systems.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer No

Document Name

Comment

We agree with the described concept of categorizing BES Cyber Systems but would want to see the suggested language used from our comments for Question 1.

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer No

Document Name

Comment

See our response to question 1. Does this question confirm that the drafting team's intent is that all Control Centers should be considered under this criterion, notwithstanding the fact that in order to control Transmission facilities (100kV and above), a NERC BA/TOP certification is required?

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer No

Document Name

Comment

The approach does not clarify the issue. The removal of the term "functional obligation" from 2.12 still does not clarify the requirement applies to TO because the capitalized term Control Center is used and that term implies functional registry (RC/BA/TOP/GOP). Clarification could be improved by using the non-capitalized term "control center" and defined as used in CIP-014. In addition, the use of the term "control" is also a source of confusion as it can be interpreted as having operational control (ie. Direct the switching operation) or physical control (perform the switching operation).

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer No

Document Name

Comment

No Comment

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer No

Document Name

Comment

Reclamation recommends that impact ratings apply to BES Cyber Systems associated with Transmission (Control Center or control room) or generation (Control Center, control room, or plant), or any identified Facilities regardless of a Responsible Entity's functional registration.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

Section 2.12 of the proposed standard conflicts with the Applicability section of the standard. Under criterion 2.12, Distribution Provider control centers could be applicable, but Distribution Providers are not included as applicable entities. The Applicability section should be the ultimate deciding factor for determining applicability. In addition, we recommend the removal of the first line in the table.

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer No

Document Name

Comment

The Proposed Definition of Control Center would have direct bearing on the outcome of how Xcel Energy interprets this question. The term would have to be finalized before an opinion could be formed.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer No

Document Name

Comment

Per the registration criteria, Transmission Operators are “responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.” As a result, this responsibility falls on directly on Transmission Operators. Further expansion of the criterion places responsibilities on Transmission Owners for activities they are not registered for.

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer Yes

Document Name

Comment

AECI agrees with the approach and believes that a BES Cyber System (BCS) should be categorized by the BCS's span of control, regardless of functional registration.

Likes 0

Dislikes 0

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer Yes

Document Name

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer Yes

Document Name

Comment

NRECA supports this approach.

Likes 0

Dislikes 0

Response

David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG

Answer Yes

Document Name

Comment

Any entity that controls Transmission service that could impact the overall grid reliability, capability, and the functionality of power delivery should be following the CIP security structure in monitoring, maintaining and reporting on those systems that have physical control capability.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

Agree. However would be clearer if the statement "...regardless of a Responsible Entity's functional registration" was included in criteria 2.12.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3

Answer Yes

Document Name

Comment

Cowlitz PUD is in agreement as long as the definition of "Control Center" is modified to clearly point to registered functions, including Transmission Owners.

Likes 5
Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer Yes

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jack Cashin - American Public Power Association - 4

Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

David Maier - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jim Nail - City of Independence, Power and Light Department - 5

Answer Yes

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response**Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE****Answer****Document Name****Comment**

No Response.

Likes 0

Dislikes 0

Response**Mary Ann Todd - Illinois Municipal Electric Agency - 4****Answer****Document Name****Comment**

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response**Jeanne Kurzynowski - Consumers Energy Company - 1 - RF****Answer****Document Name****Comment**

No comment.

Likes 0

Dislikes 0

Response

5. Criterion 2.12: Do you agree with the proposed modifications to Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer No

Document Name

Comment

See response to Question 4.

Likes 0

Dislikes 0

Response

Jim Nail - City of Independence, Power and Light Department - 5

Answer No

Document Name

Comment

As written, there will be TOP Control Centers that will drop from Medium to Low and become exempt from many of the current requirements. Given the propensity for NOT maintaining standards of performance which are not enforced/required, this WILL produce a predictable weakening of the BES's overall Cyber-Security posture.

Likes 0

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer No

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

Based on the response to Question 4, Dominion Energy recommends the following additional language modification.

“TO and TOP Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 2500 but below 3000 according to the table below. The "aggregate weighted value" for a TO or TOP Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.”

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer No

Document Name

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the methodology stated in the response to Question 1.

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"See our comments, rationale and alternate proposal as provided in our response to question 2."

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0
Dislikes	0
Response	
<p>Russell Noble - Cowlitz County PUD - 3</p>	
Answer	No
Document Name	
Comment	
<p>Cowlitz PUD fully supports establishment of medium and low impact TOP/TO Control Centers, and believes that summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls is the desired approach. However, it is possible that Criterion 2.12 can be interpreted by the Regional Entity contrary to this approach. As written, Criterion 2.12 appears to mandate a “Control Center impact designation” by summing the weighted values of Transmission Lines that the Control Center monitors and controls via any methodology. Cowlitz PUD has obtained confirmation from regional compliance personnel opinion in this regard. Monitoring and control can include Control Center operator verbal communication with field personnel, or non-programmable electronic devices <i>along with</i> BES Cyber Assets. The result is the BES Cyber System is not categorized by evaluating its integral importance to the BES asset’s function, it is categorized based on mere association with the asset regardless of whether it is necessary for the asset’s complex function.</p> <p>Cowlitz PUD supports the APPA suggested alternate proposal.</p>	
Likes	5
Dislikes	0
<p>Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long</p>	
Response	
<p>Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1</p>	

Answer	No
Document Name	
Comment	
See our comments, rationale and alternate proposal as provided in our response to question 2.	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
Answer	No
Document Name	
Comment	
Removing functional obligation does not remove the conflict with the existing definition of Control Center for performing the functional obligation of a TOP. Removing Control Center and replacing with the control center concept used in CIP-014 would provide clarification.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
<p>IID believes that summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls is the desired approach, but Criterion 2.12 can be interpreted by the Regional Entity contrary to this approach. As written, Criterion 2.12 appears to mandate a "Control Center impact designation" by summing the weighted values of Transmission Lines that the Control Center monitors and controls via any methodology. Monitoring and control can include Control Center operator verbal communication with field personnel, or non-programmable electronic devices along with BES Cyber Assets. The result is the BES Cyber System is not categorized by evaluating its integral importance to the BES asset's function, it is categorized based on mere association with an asset regardless of whether it is necessary for the asset's complex function.</p> <p>Further, IID has concerns a Control Center that may be used for various functions, and may have several isolated BES Cyber Systems (BCS) to cover each. In addition, applicable entities should be encouraged to apply technology which is not subject to the inherent vulnerabilities of programmable devices using routable protocol. Removal of key high risk control to highly secure technology should be removed from the "aggregate weighted value" of the BES Cyber Systems used to monitor and control.</p>	

IID supports the following possible modifications:

1. At the beginning of Section 2: Each BES Cyber System, not included in Section 1 above, integral in the operation of the following:
2. For Rational for criterion 2.12, last paragraph, second sentence: ... "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center's or backup Control Center's BES Cyber System...
3. For criterion 2.12: Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center's or backup Control Center's BES Cyber System.

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

No

Document Name

Comment

The proposed changes to criterion 2.12 will allow some entities, currently rated at medium impact, to change their control center(s) impact rating to low. This change could significantly increase both cyber and physical risks to reliability for the entity moving to low, and also the entities they are connected to. The low impact CIP requirements are not adequate protections for some entities.

Likes 0

Dislikes 0

Response

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer

No

Document Name

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
<p>Based on the lack of clarity that exists regarding whether criterion 2.12 would be applicable to all Control Centers, not just TO Control Centers, Duke Energy does not support the proposed modifications. In the CIP V5 Issues for Standard Drafting Team Consideration document, the V5TAG group suggests the following:</p> <p><i>“Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.”</i></p> <p>The sentence above from the V5TAG document, specifically makes reference to a need to clarify requirements on TO Control Centers that perform functional obligations of a TOP. As we have stated previously, this proposed modification could be interpreted to include all Control Centers, not just TO Control Centers. Was it the drafting team’s intent to clear up the “functional obligations of a TOP” issue by inserting the phrase “that monitor and control BES Transmission Lines” into the criterion of 2.12? Perhaps a better understanding of what “performing the functional obligations of” would be beneficial, since it is commonly used throughout Attachment 1.</p> <p>If it was the drafting team’s intent that this proposed modification to the criterion only refer to TO Control Centers, we recommend revising said criterion to explicitly reference TO Control Centers.</p>	
Likes	0
Dislikes	0
Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA</p>	
Answer	No
Document Name	
Comment	
<p>Pleae see our comments for Question 1.</p>	
Likes	0
Dislikes	0
Response	
<p>Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable</p>	
Answer	No

Document Name	
Comment	
See our comments, rationale and alternate proposal as provided in our response to question 2.	
Likes 0	
Dislikes 0	
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	No
Document Name	
Comment	
MMWEC supports the comments submitted by APPA, and suggests adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	No
Document Name	
Comment	
Public power supports the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers. However, as proposed, Criterion 2.12 is ambiguous as to how the "aggregate weighted value" is derived. Is it derived by summing the values for all Transmission Lines monitored and controlled by a Control Center, or should it be derived by summing the value for Transmission Lines monitored and controlled by BES Cyber Systems located at the Control Center? Also, the criterion is not clear on whether "control" refers to control by personnel at the Control Center (e.g., by verbal instruction to field personnel) or to control by a BES Cyber System.	
APPA suggests adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."	

Public power appreciates the SDT efforts for clarifying the applicability requirements for a TO Control Center that performs the functional obligations of a TOP. We have some suggested language for Criterion 2.12 that we feel removes some ambiguity and possible interpretation questions. Our suggested language is as follows:

“Cyber Assets used to control BES Transmission lines, located at Control Centers or backup Control Centers, where the summed weighted value (according to the table below) of each BES Transmission Line controlled and monitored exceeds 6000.”

Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
---------	--

Dislikes 0	
------------	--

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

Hydro One supports comments submitted by NPCC RSC.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 5 response.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Don Schmit - Nebraska Public Power District - 5

Answer	No
---------------	----

Document Name	
Comment	
See comments on question #1.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	No
Document Name	
Comment	
<p>We support the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers. However, as proposed, Criterion 2.12 is ambiguous as to how the "aggregate weighted value" is derived. Is it derived by summing the values for all Transmission Lines monitored and controlled by a Control Center, or should it be derived by summing the value for Transmission Lines monitored and controlled by BES Cyber Systems located at the Control Center? Also, the criterion is not clear on whether "control" refers to control by personnel at the Control Center (e.g., by verbal instruction to field personnel) or to control by a BES Cyber System.</p> <p>We suggest adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."</p>	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
See the response to question 2 above	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
See comments on question #2.	
Likes	0
Dislikes	0
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes	0
Dislikes	0
Response	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	No
Document Name	
Comment	
<p>NRG has a concern that there may be confusion on what the drafting team's intent is in reference to proposed language pertaining to BES Cyber System's span of control instead of the BES Cyber System monitors and controls. Industry interpretation of the current language leads NRG stakeholders to believe that the Rationale information may not match up correctly with the CIP-002-6 Standard. (NRG requests clarity on the operation authority versus capability). NRG requests that the drafting team provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.</p>	

Question: Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element? Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations? It seems that most if not all TOPs are Medium and this can reduce them to Low which may be a concern for the industry.

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer

Yes

Document Name

Comment

Suggest 3000 points to be in-line with Criterion 2.5. Concerns that entities with large amounts of 100-199kV lines would be excluded (6000 points = 24 100kV lines).

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer

Yes

Document Name

Comment

NRECA supports the proposed modifications.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer

Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer

Yes

Document Name

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Yes

Document Name

Comment

SNPD only agrees with the weighted approach to identify ratings of Control Centers. A BES Cyber System that is an integrated part of a Control Center, and involves one or more BES Reliability Operating Service (BROS), should have a Medium Impact rating by association. The introduction of Span of Control, from the SDT is somewhat confusing language for SNPD.

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Aaron Austin - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bette White - AES - Indianapolis Power and Light Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECl & Member G&Ts

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	

MidAmerica would like to change its answer for this question to NO.

MidAmerican agrees with EEI's comments. Please see EEI's Comments below:

See our comments, rationale and alternate proposal as provided in our response to question 2.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

6. Implementation Plan: Do you agree with the SDT's proposed Implementation Plan? If you agree with the proposed implementation time period, please note the actions you will take that require this amount of time to complete. If you think an alternate implementation time period is needed – shorter or longer - please propose an alternate implementation plan and provide a detailed explanation of actions and time needed to meet the implementation deadline.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

It is premature in our opinion to comment on the implementation plan because Ameren disagrees with the revisions.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 6 response

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer No

Document Name

Comment

It is premature to comment on the implementation plan because EEI disagrees with the proposed revisions to the standard.

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer No

Document Name

Comment

Based on the lack of clarity on the scope of criterion 2.12, we cannot agree that 12 months would be a sufficient time to address impact changes resulting from an unplanned change to the system.

Likes 0

Dislikes 0

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer No

Document Name

Comment

Enforcement schedules triggered by a system change or periodic review should be incorporated directly within the Standard, not within a standalone Implementation Plan. An example of doing this is CIP-014-2 R5. The “unplanned changes compliance implementation table” in the Implementation Plan creates a situation where this Implementation Plan is never fully vested/implemented. An Implementation Plan should be used to dictate timelines required to implement a requirement, where timelines allowing for compliance maintenance (after Standard is fully implemented) should be incorporated directly within the standard, which allows the Implementation Plan itself to expire. This supports NERC’s implementation timeline reporting in Col L, [here](#).

Likes	1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes	0	
Response		
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1		
Answer		No
Document Name		
Comment		
It is premature to comment on the implementation plan because MEC disagrees with the revisions.		
Likes	0	
Dislikes	0	
Response		
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3		
Answer		No
Document Name		
Comment		
No Comment		
Likes	0	
Dislikes	0	
Response		
Vivian Vo - APS - Arizona Public Service Co. - 3		
Answer		No
Document Name		
Comment		
AZPS recommends that the proposed implementation time period be extended to 24 months for all options. Regardless of whether a facility's categorization is revised from Low to Medium or Medium to High, the effort required would involve the design and implementation of new or different technology, new or revised processes, procurement and contracting efforts, etc. To design and implement an approach to compliance could – alone – take 12 months. When the additional time required for and uncertainty associated with the execution and completion of the supply chain and		

procurement processes are considered, implementation efforts could easily exceed 12 months. For this reason, implementation efforts should be allotted 24 months for completion as such timeline better aligns with the time needed for analysis, procurement of long lead items, and actual work.

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"It is premature to comment on the implementation plan because EEI disagrees with the revisions."

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

No

Document Name

Comment

Reclamation recommends an initial implementation period of 18 months to allow entities time to determine the effects of the revised Impact Rating Criteria and an additional 18 months to comply.

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

No

Document Name

Comment

N&ST agrees with the proposed implementation time frames in the draft Implementation Plan. However, N&ST believes there a number of issues with the accompanying narrative that should be addressed:

- Third paragraph under heading, "Planned and Unplanned Changes:" N&ST does not believe it is possible for "unplanned" changes, defined in the Implementation Plan document as changes not planned and implemented by the responsible entity, to be made to one or more of that entity's BES Cyber Systems.

- That same paragraph describes a "...scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1,..." N&ST believes this condition is logically impossible. An unplanned change, outside of the hypothetical transmission substation, could only result either in (a) an existing Cyber Asset, not previously identified as a BES Cyber Asset, becoming part of a new or existing BES Cyber System, or (b) a low impact BES Cyber System being recategorized as a medium impact BES Cyber System.

N&ST recommends the following changes to the Implementation Plan's timeline table:

- For ease of reference, table entries should be numbered.

- The Implementation Plan should state explicitly that the table's third and fourth entries (an existing BES Cyber System is recategorized from medium to high or from low to medium impact) applies to responsible entities that have previously identified at least one medium impact BES Cyber System.

- N&ST finds it difficult to envision a scenario wherein a new high or medium impact BES Cyber System must be implemented as the result of an unplanned change (first and second entries in table). At the same time, N&ST believes it is possible, if unlikely, that an existing Cyber Asset could be recategorized as a BES Cyber Asset as the result of an unplanned change. If this is the scenario the Drafting Team had in mind, these timeline table entries should be clarified. Otherwise, N&ST recommends they be deleted.

Likes	0
Dislikes	0
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The question asks, "please note the actions you will take that require this amount of time to complete", although there is no time afforded entities to complete any actions. The proposed Implementation Plan states "Where approval by an applicable governmental authority is required, Reliability	

Standard CIP-002-6 shall become effective on the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority." This does not allow entities adequate time to achieve compliance with 'main R' requirements to have 'one or more documented processes' at the time of approval. Updates to entity policies, programs, plans, and procedures would be required, regardless of whether or not the modifications result in the identification of new, or reclassification of existing BES Cyber Systems at Control Centers.

The Implementation Plan does explicitly state "For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards." However, there is no explicit clarification whether the changes to CIP-002-6 are considered a *Planned* change, or an *Unplanned* change. This impacts entities where there is no change to BES Cyber System categorization, but yet policies, programs, plans, and procedures must comply as of the effective date of the new approved standard. For the 24 month implementation clause above, this needs to also explicitly state "This includes changes or updates necessary to entity policies, programs, plans or procedures to address these modifications in CIP-002-6."

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer

No

Document Name

Comment

The implementation time period needed would be contingent on the status of the changes to the definition of Control Center.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer

No

Document Name

Comment

The following language is not adequately clear.

"Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)" (24 months)

This language needs to be clarified to clearly identify that 12 months is for the first medium or high impact BES Cyber System for this asset.

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer Yes

Document Name

Comment

SNPD does not have comments on Question 6.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECl & Member G&Ts

Answer Yes

Document Name

Comment

AECl requests the SDT to revise the implementation plan to provide added clarity. AECl suggests moving the statement, "For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards." to the beginning of the Planned/Unplanned Changes section of the Implementation Plan. It is confusing to read through all of the planned/unplanned options in the associated table and finally conclude with the statement that is most impactful to Responsible Entities.

Likes 0

Dislikes 0

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	
Likes	0
Dislikes	0
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	
We agree with the intent of the implementation plan but feel that the unintended consequences of potential interpretations could bring assets into scope, thereby requiring recalibration of compliance programs in an ongoing manner.	
Likes	5 Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes	0
Response	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Salt River Project supports comments submitted by APPA.	
Likes	0
Dislikes	0

Response

Richard Vine - California ISO - 2

Answer Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer Yes

Document Name

Comment

NRECA supports the proposed implementation plan.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

Consider further clarification of the classification of planned or unplanned changes. Existing definitions are vague with regard to change of facility ownership, criterion that are based on agreements (2.7 NUC-001) or other entities or internal.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3

Answer Yes

Document Name

Comment

Cowlitz PUD supports APPA comment.

Likes 1 Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer Yes

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Quintin Lee - Eversource Energy - 1, Group Name Eversource Group****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**David Gordon - Massachusetts Municipal Wholesale Electric Company - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Quebec TransEnergie - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bette White - AES - Indianapolis Power and Light Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Maier - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

While Texas RE does not necessarily object to the proposed Implementation Plan timeframes, the IP, as currently drafted, could introduce ambiguity regarding the expected compliance timelines for entities with Control Centers that are would be newly subject to the proposed CIP-002-6 Criteria 2.12 definition. In particular, Texas RE requests the SDT should clarify whether the change to the Control Center criteria would constitute a planned or unplanned change.

The standard will become effective immediately upon the effective date of the FERC order approving the revisions. However, the new criteria presumably will interact with the impact rating review criteria set forth in CIP-002-5.1 R2. Specifically, Transmission Owners with Control Centers that satisfy the proposed 2.12 criteria presumably will have to identify those Control Centers during its periodic 15-month review of its Medium Impact BES Cyber System identifications. As such, depending on the time of the approval, entities could have as much as 15 months to properly categorize and implement medium impact controls for any Control Centers now captured by the changes to the CIP-002-5.1 Criteria 2.12 language. Further, entities may possibly have an additional 12 months beyond the 15 month categorization window if the SDT changes fall within the definition of an “unplanned change.” That is, “any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity.” Texas RE recommends that the SDT clarify this timeline, and, particularly, whether the SDT intends for the additional 12-month period for unplanned changes to be applicable in these circumstances.

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Document Name

Comment

MidAmerica would like to change its answer for this question to NO.

MidAmerican agrees with EEI's comments. Please see EEI's Comments below:

It is premature to comment on the implementation plan because EEI disagrees with the revisions.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer

Document Name

Comment

No comment.

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Document Name

Comment

As the IESO does not own or operate BES Transmission Lines we have no opinion or comment on the implimentation plan.

Likes 0

Dislikes 0

Response

7. The SDT considered a number of approaches and determined that proposed CIP-002-6 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for a more cost effective approach that addresses the reliability objective, please provide your recommendation and, if appropriate, technical justification.

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer No

Document Name

Comment

Reclamation recommends that the Impact Rating Criteria in CIP-002 Attachment 1 be simplified, using the methodology described in the response to Question 1, to reduce the overall impact of CIP-002-6 and allow entities to reduce the time spent "review[ing] the identifications in Requirement R1 and its parts (and update[ing] them if there are changes identified) at least once every 15 calendar months" and the cost of implementing the standard.

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"It is premature to comment on the cost effectiveness of the proposed changes because EEI disagrees with the revisions."

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

Removal of the guidelines and technical basis on which entities implemented their CIP-002 BES Cyber System identifications and classifications could cause significant re-work if it results in compliance interpretations other than what the SDT intended. Re-work is not cost effective.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name

Comment

It is premature to comment on the cost effectiveness of the proposed changes because MEC disagrees with the revisions.

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer

No

Document Name

Comment

See our response to question 6. Without clarity on the scope, it is difficult to determine the cost effectiveness.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer No

Document Name

Comment

It is premature to comment on the cost effectiveness of the proposed changes because EEI disagrees with the revisions.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 7 response.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

See the response to question 6 above.

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson

Answer No

Document Name

Comment

Item 7 is ambiguous and needs to be explained. SDG&E seeks clarification to what the “cost effective manner” element is of this proposed change to CIP-002-5.1.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer	Yes
Document Name	
Comment	
Colorado Srings Utilities supports Cowlitz PUD and APPA comments	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
AZPS agrees that the SDT's proposal meets the reliability objectives in a cost effective manner so long as a reasonable implementation period, i.e., at least 24 months, is allotted. Otherwise, entities to which these modifications are applicable may expend significant resources unnecessarily to meet timeframes that were, at their time of proposal, unreasonable. Such unnecessary expenditures would gravely adversely impact the cost-effectiveness of the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Cowlitz PUD supports APPA comment.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Richard Vine - California ISO - 2	

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Salt River Project supports comments submitted by APPA.	
Likes 0	
Dislikes 0	
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
MMWEC supports the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers.	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	

Comment	
Based on the perception of the SDT intent, public power agrees with the weighted values for transmission lines that the BES cyber system monitors and controls approach and that the allowing for low impact Control Centers is a positive action.	
The changes proposed should reduce cost and/or potentially provide flexibility in compliance options.	
Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

SNPD does not have comments on Question 7.

Likes 0	
Dislikes 0	

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer	Yes
--------	-----

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Quintin Lee - Eversource Energy - 1, Group Name Eversource Group****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECl & Member G&Ts

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Document Name

Comment

As the IESO does not own or operate BES Transmission Lines we have no opinion or comment on the implimentation plan.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer

Document Name

Comment

The SDT should strongly consider replacing CIP-002 and the associated CIP standards with an alternative non-prescriptive approach that focuses on effective cyber and physical security and adapt the enforcement approach to be consistent with those used in financial auditing. This alternative approach would reduce costs and allow Registered Entities to focus on maintaining a secure power grid .

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer

Document Name

Comment

We have not performed a cost analysis on the proposed changes.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer	
Document Name	
Comment	
IMEA supports APPA comments.	
Likes 0	
Dislikes 0	
Response	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	
Document Name	

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

8. If you have additional comments on proposed CIP-002-6, Attachment 1, Criterion 2.12 that you have not provided in response to the questions above, please provide them here.

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer

Document Name

Comment

SCE does not agree with the first paragraph that has been inserted into the Guidelines and Technical Basis (GTB) section of the proposed standard.

SCE used the existing Guidelines and Technical basis section of CIP-002 (and other CIP standards) to inform the implementation of NERC compliant CIP programs and, consequently, SCE does not think that NERC should remove this section from the proposed standard without providing a replacement process to inform the understanding of the impact rating criteria in CIP-002, and the impact of BES Cyber System impact ratings on the applicability of other CIP standards.

In proposed standard CIP-002-6, NERC states that the guidance that is normally provided in the GTB section of the standard could be moved into the accompanying Implementation Guidance document, however, NERC does not provide any assurance that the Implementation Guidance will be released in a timely manner, or if industry participants would have the opportunity to vet and/or approve the information. Consequently, SCE does not agree with NERC's proposal to remove the GTB sections of CIP-002-6 unless NERC can provide clear and discrete next steps about what implementation information will be made available to industry participants, when NERC will release the information, and NERC provides assurance that industry stakeholders will have an opportunity to reviewing/vet the information prior to its implementation.

Furthermore, SCE does not believe that the Implementation Guidance document is an appropriate place to present the information that would typically be accessible in the GTB section of the standard. Currently, the GTB section of the standards provides valuable examples that clarify the specific compliance circumstances and variables NERC could/would review during the NERC audit process. Additionally, the GTB provides industry stakeholders insight to the SDT's drafting process and the underlying intents of the proposed requirements in a draft standard. Conversely, Implementation Guidance documents provide a specific, NERC endorsed approach that an entity can use to achieve compliance with a particular requirement. Therefore, SCE does not think it would be appropriate to relocate information from the GTB section into Implementation Guidance. If necessary, the SDT could modify Attachment 1 of the proposed standard to include the guidance from the GTB.

Having said that, if NERC disagrees with SCE and believes that Implementation Guidance is an appropriate place to present the guidance normally found in the GTB section, SCE recommends that NERC issue the Implementation Guidance document for the review and approved of industry participants. Specifically, SCE believes that the Implementation Guidance document should pass through an industry participant ballot process before to the final ballot for CIP-002 (analogous to NERC's process for CIP-013).

Lastly, SCE is concerned that removal of the GTB may impact SCE's ability to support the approval of the proposed CIP-002-6. SCE recommends NERC address the concerns surrounding GTB before taking CIP-002-6 to a second ballot.

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Document Name

Comment

Are there any RC and TOP functional obligations that SNPD should consider, other than the services already stated in BROS?

Likes 0

Dislikes 0

Response

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Document Name

Visio-CIP V6 Diagram Trans - 20170826 - 2-12.pdf

Comment

As part of the diagrams provided for 2.12, we are providing a suggested additional diagram we feel the Standard should display in the Supplemental Material section. Even though the text for 2.12 indicates it is for "BES Transmission Lines", it is not clear that generator lead line(s) should not be counted as part of aggregated weight value of 6000. To avoid having to have separate guidance document like Criteria 2.5 has (CIP-002-5, Requirement R1, Attachment 1: Criterion 2.5 and Generator Interconnection), we recommend the standard include a third diagram which clearly indicates the generator lead line(s) are not part of the aggregated weighted value. A suggested diagram has been provided to Wendy Muller since diagrams may not import correctly to the comment portal. The file name of the diagram provided to Wendy was "Visio-CIP V6 Diagram Trans - 20170826 - 2-12.pdf"

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer

Document Name

Comment

While Vectren's subject matter experts are in agreement with the proposed modifications for CIP-002-06 Attachment 1 Criterion 2.12, Vectren does not agree with removing the Guidelines and Technical Basis (G&TB) from CIP-002-6. The G&TB addresses complex concepts and provides additional guidance regarding what should be considered when developing the methodology to categorize Facilities, systems, and equipment into high-, medium-, and low-impact ratings. It also provides clarification for some ambiguities in the requirements and has been referenced as one source in our documentation of how we arrived at our approach. It is unclear where this information will reside or how it will be maintained once it is removed from the CIP-002-6 standard. The removal of the G&TB should be delayed until a defined removal process has been developed by NERC staff, including the new location of the information.

Vectren is committed to the safety and reliability of the BES and committed to compliance excellence. We appreciate the efforts of the Standard Drafting Team and will be glad to provide any additional detail upon request. Thank you for allowing Vectren the opportunity to provide comments on this draft standard.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

We support comments offered by EEI for this question.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE

Answer

Document Name

Comment

Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document.

NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, we do not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE has the following comments regarding the Guidelines and Technical Basis:

- Texas RE requests clarification as to what Part 1, which is mentioned several times, in the Guidelines and Technical Basis refers.
- It appears version 5 is left out of the sentence on page 20: "This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment".
- Page 27 of the GTb contains a reference to functional obligations. Since the intent of this project was to clarify the use of the term "to perform the functional obligations of" and the SDT created the 2.12 criteria in Attachment 1, it does not seem necessary to use this term in the GTB. Texas RE requests the SDT ensure that it makes sense to use the term in this case.
- Page 33 contains the phrase "Associated data centers". As it is important and to be consistent, Texas RE recommends the phrase be included in criteria 2.12 of Attachment 1.
- Page 37 describes the SDT's rationale behind some of the CIP version 5 changes. It would be helpful to have this description for the CIP-002-6 changes.

Texas RE noticed the Violation Severity Level table references CIP-002-5.1a.

Likes 0

Dislikes 0

Response

Don Schmit - Nebraska Public Power District - 5

Answer

Document Name

Comment

None.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 8 response.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Document Name

Comment

PacifiCorp supports EEI comments.

Likes 0

Dislikes 0

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer

Document Name

Comment

While Vectren's subject matter experts are in agreement with the proposed modifications for CIP-002-06 Attachment 1 Criterion 2.12, Vectren does not agree with removing the Guidelines and Technical Basis (G&TB) from CIP-002-6. The G&TB addresses complex concepts and provides additional guidance regarding what should be considered when developing the methodology to categorize Facilities, systems, and equipment into high-, medium-, and low-impact ratings. It also provides clarification for some ambiguities in the requirements and has been referenced as one source in our documentation of how we arrived at our approach. It is unclear where this information will reside or how it will be maintained once it is removed from the CIP-002-6 standard. The removal of the G&TB should be delayed until a defined removal process has been developed by NERC staff, including the new location of the information.

Vectren is committed to the safety and reliability of the BES and committed to compliance excellence. We appreciate the efforts of the Standard Drafting Team and will be glad to provide any additional detail upon request. Thank you for allowing Vectren the opportunity to provide comments on this draft standard.

Likes 0

Dislikes 0

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer

Document Name

Comment

Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document

Likes 0

Dislikes 0

Response

Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer

Document Name

Comment

PSEG generally supports EEL's comments on Questions 8. PSEG does not agree with NERC's approach to remove the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale.

Likes 4

PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph; PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes 0

Response

Jack Cashin - American Public Power Association - 4

Answer

Document Name	
Comment	
<p>The possible new interpretations could impact the application of other criteria. (2.11 and 2.13)</p> <p>The removal of the Guidelines and Technical Basis (GTB) section from the standard reduces the standard's continuity and authority. This removal makes it so that the language in the requirements includes the details currently included in guidance. Such inclusion makes requirements out of guidance.</p>	
Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
<p>NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard while removing the original SDT intent by which was the basis for industry approval and implementation.</p> <p>The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.</p> <p>It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended "to support the implementation of the associated Reliability Standard." Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT's intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.</p> <p>It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC and Regional auditors in understanding the SDT's intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.</p> <p>EEI is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot.</p>	

Likes 1	PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	
Document Name	
Comment	
<p>Duke Energy has some concerns regarding the removal of the Guidelines and Technical Basis Section (GT&B) of the standard. While the GT&B section is not considered to be an enforceable part of the standard (as opposed to requirements), it may be used by some entities to get a better understanding of the standard's expectations, as well as determining a compliance approach. If the GT&B section is removed from the standard, we recommend that it be incorporated into ERO Enterprise-Endorsed Implementation Guidance.</p>	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
<p><i>Provide clarity: If each end of a line is controlled and monitored by separate Control Centers (same or different entities) is the line weight counted for each Control Center?</i></p>	
Likes 0	
Dislikes 0	
Response	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
<p>Salt River Project supports comments submitted by APPA.</p>	

Likes 0

Dislikes 0

Response

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

Document Name

Comment

Other factors besides transmission values, such as customers served, should be used to determine an entities' impact. It should not be assumed that all entities will voluntarily implement and maintain security controls above the low impact threshold if not mandated to do so. The low impact requirements may not be adequate in all situations.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Document Name

Comment

IID fully supports SDT efforts so far, and regrets the need for submitting a negative ballot. However, the application interpretations received from regional auditors of the proposed criterion is cause for serious concern, and can impact application of other criteria in similar fashion.

Likes 0

Dislikes 0

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer

Document Name

Comment

LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company (LKE) submits these comments for NERC's consideration. LKE strongly supports the comments submitted by Edison Electric Institute (EEI) with respect to the Guidelines and Technical

Basis (GTB) portion of the draft changes to the standard. Specifically, LKE is deeply concerned with the proposed approach of removing the GTB section of the standards without the simultaneous posting of **1) Technical Rationale** prepared by the Standards Drafting Team for industry comment or **2) potential Implementation Guidance** developed through the Compliance Guidance policy. It is our understanding that the Standards Committee is working with NERC staff to develop a process for removal of the GTB sections from standards. We recommend that GTB sections not be removed from any standard until that process has been defined. As detailed in section 2.5 of the Standards Processes Manual (Rules of Procedures Appendix 3A), Application Guidelines are included, among other reasons, “to support the implementation of the associated Reliability Standard,” “establish relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” In many cases, and specifically in the case of CIP-002-5.1a, the GTB plays a critical role in determining the scope of the standard to which it applies. Consequently, removal of GTB sections without simultaneously publishing a Technical Rationale document as proposed for this standard creates unnecessary and significant ambiguity. Furthermore, removing the GTB may inadvertently contradict the Standards Process Manual and we suggest NERC should avoid any such appearance.

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

Document Name

Comment

Guidelines and Technical Basis

At NERC’s direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

The NSRF has concerns with removing the Guideline and Technical Basis from all Standard(s). Currently Entities feel they vote for the “entire standard” including the Guideline and Technical Basis. The NSRF understands that Entities are actually voting for the Requirements but the perception is that FERC approves all the verbiage and sections to the Entire Standard.

Likes 0

Dislikes 0

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees with Edison Electric Institute’s comments regarding the removal of the Guidelines and Technical Basis (GTB) from the Reliability Standard prior to final ballot. CenterPoint Energy does not agree with NERC’s proposal to remove the GTB without providing guidance on how the information in the GTB will be retained. CenterPoint Energy believes the GTB in CIP-002 provides pertinent information that establishes guidance for identifying and categorizing the BES Cyber Systems that would be subject to CIP-002, which sets the foundation of applicability for the other CIP standards. CenterPoint Energy is concerned that the removal of the GTB will provide less guidance to entities regarding the technical basis for the requirements and the intent of the Standard Drafting Team, which has been relied upon by the industry and regulatory authorities.

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer

Document Name

Comment

FirstEnergy supports the comments supplied by EEI regarding the removal of the Guidelines and Technical Basis Section from the CIP-002 Standard. This section provides valuable application guidance that the industry has relied on in implementing the CIP-002 Standard, and should remain part of the Standard.

Likes 0

Dislikes 0

Response

Richard Vine - California ISO - 2

Answer

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer	
Document Name	
Comment	
<p>Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document.</p>	
Likes	0
Dislikes	0
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
<p>NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.</p> <p>The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.</p> <p>It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended "to support the implementation of the associated Reliability Standard." Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT's intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.</p> <p>It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT's intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.</p> <p>MEC is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot.</p>	
Likes	0
Dislikes	0

Response

Tyson Archie - Platte River Power Authority - 5

Answer

Document Name

Comment

Platte River Power Authority (PRPA) supports the comments provided by the American Public Power Administration (APPA).

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer

Document Name

Comment

NRECA appreciates the hard work of the drafting team over a long period of time on complex issues.

Likes 0

Dislikes 0

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer

Document Name

Comment

NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, Con Edison does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a

possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

Likes 0

Dislikes 0

Response

Russell Noble - Cowlitz County PUD - 3

Answer

Document Name

Comment

Cowlitz PUD supports APPA comment.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Document Name

Comment

MEC supports the comments of EEI on this question. The content of the guidelines and technical basis is essential to convey the SDT's intent, which was the basis for industry approval and implementation and therefore must continue to be a part of the standard. Also, the proposal to remove the

guidelines and technical basis from CIP-002 is out of scope of the Standards Authorization Request, which states, "Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary." This indicates continuation of the guidelines and technical basis, not removal.

MEC also agrees with EEI's comments for questions #8

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

Document Name

Comment

Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

Document Name

Comment

Utility Services supports the efforts of the Standard Development Team to date and believe that the revised language for Criteria 2.12 is a significant incremental step forward which will focus efforts on the most critical locations. We are aware of issues with the interpretation of the of the TOCC proposed version of Criteria 2.12 and encourage the Standard Development Team to clarify the specific language of criteria 2.12 to clarify the scoring application of Criteria 2.12. To that end, Utility Services supports the comments of the NPCC Regional Standards Committee suggesting revision of the criteria for clarity.

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

Document Name

Comment

Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).

Likes 0

Dislikes 0

Response

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"

NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended "to support the implementation of the associated Reliability Standard." Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT's intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT's intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

EEl is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot."

Likes 1

PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer

Document Name

Comment

Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer

Document Name

Comment

NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

Of significant concern is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. Dominion Energy does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended "to support the implementation of the associated Reliability Standard." Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT's intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT's intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

Likes	1	Long Island Power Authority, 1, Ganley Robert
-------	---	---

Dislikes	0	
----------	---	--

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer	
---------------	--

Document Name	
----------------------	--

Comment	
----------------	--

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes	0	
-------	---	--

Dislikes	0	
----------	---	--

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer	
---------------	--

Document Name	
----------------------	--

Comment

(No additional comments)

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer**Document Name****Comment**

We suggest that rationale similar to Criterion 2.12 should also be referenced for 1.3.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer**Document Name****Comment**

1. As this team is planning to submit the Guidelines and Technical Basis as a separate document from the Standard itself, Seminole requests the drafting team to revise the language “adversely impact the reliable operation” and make it more clear. This phrase is very unclear. How is an adverse impact quantitatively measured?
2. The Interpretation listed in Section C on page 13 of the redline, is that part of the Reliability Standard, or more of an Associated Document?
3. Should the Guidelines and Technical Basis be listed under Associated Documents (Section F) on p. 13 of 43 of the redline?
4. In the Guidelines and Technical Basis, the SDT has differentiated between Control Centers and backup Control Centers. However, in portions of the redline changes (see page 34 for example), the SDT only references Control Centers. This is confusing as Seminole isn’t sure if the drafting team purposely means not to include backup Control Centers in these sections where they are not specifically identified. The team should only use one term or define backup Control Centers (make it a NERC defined term) and reference both throughout the document.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Document Name

Comment

SVP appreciates the effort by the SDT to look at and improve criterion 2.12

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Document Name

Comment

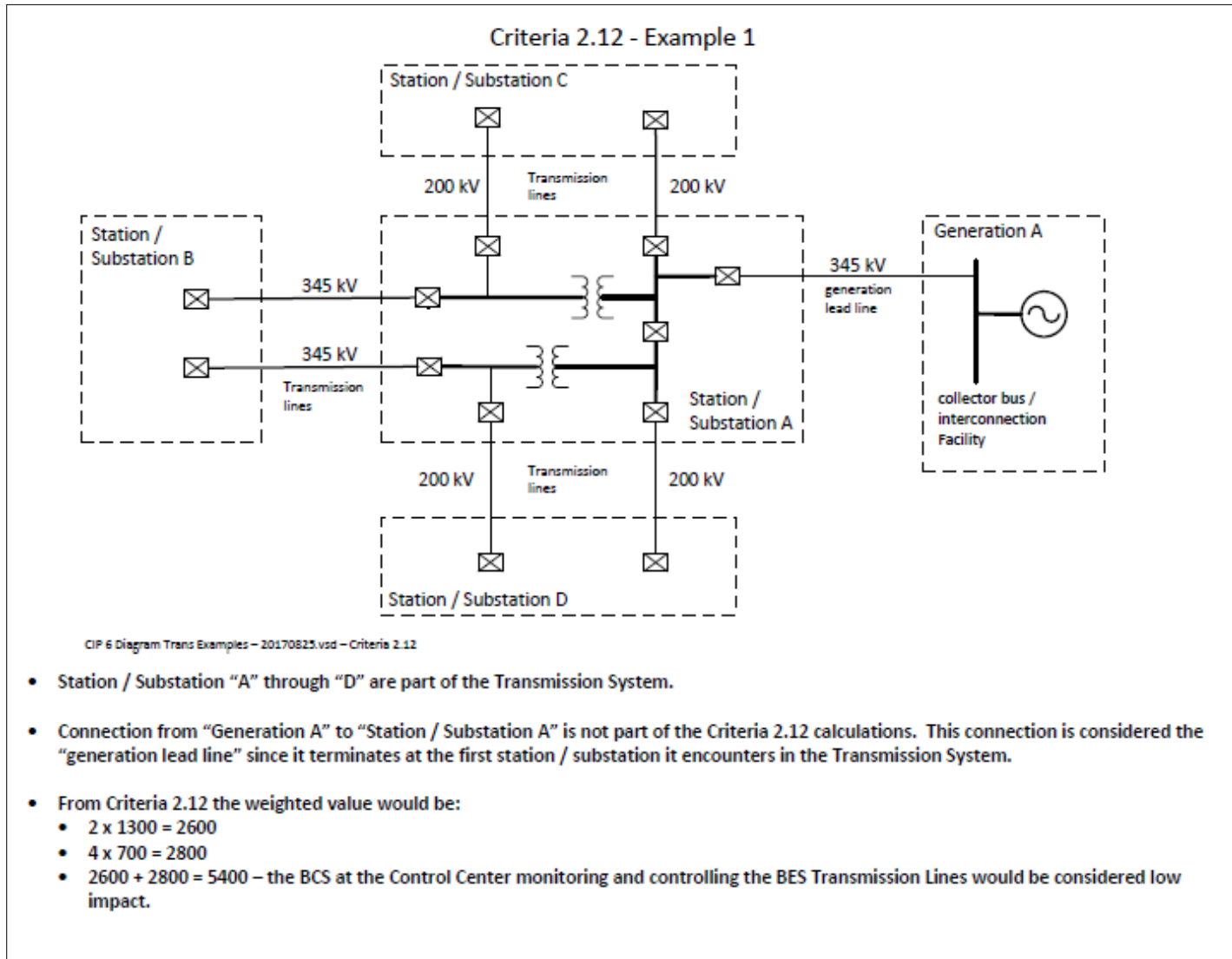
I am in agreement with the proposed changes.

Likes 0

Dislikes 0

Response

Diagram provided by Michael Johnson Burns & McDonnell



Consideration of Comments

Project Name:	2016-02 Modifications to CIP Standards CIP-002-6
Comment Period Start Date:	9/14/2017
Comment Period End Date:	10/30/2017
Associated Ballot:	2016-02 Modifications to CIP Standards CIP-002-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 192 different people from approximately 129 companies representing the 10 Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, [Howard Gugel](#) (via email) or at (404) 446-9693.

Questions

1. Criterion 2.12: In the V5TAG Transfer Document, the V5TAG requested the SDT to “clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the capability to operate switches, breakers, and relays in the BES.” The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to make this clarification. Do you agree that the revision clarifies the applicability of Criterion 2.12? If not, please provide your rationale and an alternate proposal.
2. Criterion 2.12: The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to be similar to the construct used in Criterion 2.5. Do you agree with the SDT’s approach in the modified criterion to evaluate a BES Cyber System’s span of control by summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls? If not, please provide your rationale and an alternate proposal.
3. Criterion 2.12: Do you agree with the 6000 aggregate weighted value that is used in Criterion 2.12 to establish the minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control Transmission? If not, please provide your rationale and an alternate proposal.
4. Criterion 2.12: The SDT modified Criterion 2.12 to categorize BES Cyber Systems associated with Control Centers that monitor and control Transmission regardless of a Responsible Entity’s functional registration. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.
5. Criterion 2.12: Do you agree with the proposed modifications to Criterion 2.12? If not, please provide your rationale and an alternate proposal.
6. Implementation Plan: Do you agree with the SDT’s proposed Implementation Plan? If you agree with the proposed implementation time period, please note the actions you will take that require this amount of time to complete. If you think an alternate implementation time period is needed – shorter or longer - please propose an alternate implementation plan and provide a detailed explanation of actions and time needed to meet the implementation deadline.
7. The SDT considered a number of approaches and determined that proposed CIP-002-6 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for a more cost

effective approach that addresses the reliability objective, please provide your recommendation and, if appropriate, technical justification.

8. If you have additional comments on proposed CIP-002-6, Attachment 1, Criterion 2.12 that you have not provided in response to the questions above, please provide them here.

The Industry Segments are:

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	3	RF	FirstEnergy Corporation	Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Southern Company - Southern Company Services, Inc.	Brandon Cain	1,3,5,6	FRCC,MRO,NPCC,SERC,SPP RE,Texas RE,WECC	Southern Company	Katherine Prewitt	Southern Company - Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Southern Company - Alabama Power Company	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					William D. Shultz	Southern Company - Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company - Southern Company Generation and Energy Marketing	6	SERC
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Colby Bellville	Colby Bellville		FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
SRC	David Francis	2,3	FRCC,MRO,NPCC, RF,SERC,SPP RE,Texas RE,WECC	SRC + SWG	Gregory Campoli	New York Independent System Operator	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Terry Bilke	Midcontinent ISO, Inc.	2	RF
					Elizabeth Axson	Electric Reliability Council of Texas, Inc.	2,3	Texas RE
					Ben Li	IESO	1	MRO
					Drew Bonser	SWG	NA - Not Applicable	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Darrem Lamb	CAISO	2	WECC
					Matt Goldberg	ISONE	2	NPCC
Associated Electric Cooperative, Inc.	Mark Riley	1		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative (Missouri)		
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Seattle City Light	Paul Haase	1,3,4,5,6	WECC	Seattle City Light	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Haynes	Seattle City Light	5	WECC
					Bud Freeman	Seattle City Light	6	WECC
					Paul Haase	Seattle City Light	1,3,4,5,6	WECC
					Ginette Lacasse	Seattle City Light	1,3,4,5,6	WECC
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Generation Inc.		
					Quintin Lee	Eversource Energy	1	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Ed	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Brian O'Boyle	Con Ed	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Colorado Springs Utilities	Shannon Fair	6		Colorado Springs Utilities	Kaleb Brimhall	Colorado Springs Utilities	5	WECC
					Charlie Morgan	Colorado Springs Utilities	3	WECC
					Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Megan Wagner	Westar Energy	6	SPP RE
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
PSEG	Sheranee Nedd	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Karla Jara	PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co	1	RF

1. Criterion 2.12: In the V5TAG Transfer Document, the V5TAG requested the SDT to “clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the capability to operate switches, breakers, and relays in the BES.” The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to make this clarification. Do you agree that the revision clarifies the applicability of Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer No

Document Name

Comment

We believe further language is specifically required in Criterion 2.12 to clarify that the functional registration of Transmission Owner and Transmission Operator apply. Per the registration criteria, Transmission Operators are “responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.” As a result, this responsibility falls on directly on Transmission Operators. Further expansion of the criterion places responsibilities on Transmission Owners for activities they are not registered for.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. CIP-002-5.1a is a Critical Infrastructure Protection standard that requires Responsible Entities to perform a categorization of their BES Cyber System(s). BES Cyber System categorization is based on the span of control of BES Cyber System(s), not functional registration. Transmission Owners are currently required to determine if they perform the functional obligation of a Transmission Operator under Criterion 2.12. Any Transmission Owner that operates BES Cyber System(s), associated with a Control Center, that can functionally control BES Transmission Facilities at one or more locations should be identified as medium impact in accordance with Criterion 2.12. The proposed Criterion 2.12 attempts to provide further clarity to TOs through a bright line approach and does not expand beyond the current scope of Criterion 2.12.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	
Comment	
<p>The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.</p> <p>In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, Dominion Energy suggests that the language be changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT thanks you for your comment and asserts that the language in the GTB is consistent with the language in Attachment 1, Section 2. While the SDT agrees that the “associated with” language could be more precise, this language exists in the currently approved version of CIP-002, and addressing the “associated with” language is not related to the SDT’s currently proposed modifications to CIP-002.</p>	
Jeanne Kurzynowski - Consumers Energy Company - 1 - RF	
Answer	No
Document Name	
Comment	

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

No

Document Name

Comment

Although the operation of breakers and switches is discussed in the Supplemental Material, it is not clear how Criterion 2.12 addresses whether “the TO has the capability to operate switches, breakers, and relays in the BES.”

CIP-002 is fundamental to determining which Cyber Assets are within scope. Reclamation recommends the impact rating of a BES Cyber System be determined by its possible impact on the Bulk Electric System, not where it resides (Control Center or any other location), how it is identified (virtual, non-virtual, hardware, software, etc.), and regardless of a Responsible Entity’s functional registration. Following this principle, phrases such as “performing the functional obligations of” are unnecessary.

Reclamation also recommends simplifying the Impact Rating Criteria using the methodology described below.

BES Cyber Systems are to be rated as high, medium, or low impact as follows:

A high impact BES Cyber System has one or more of the following characteristics:

- Is used to operate transmission lines of 500kV or above
- Supports a sum greater than 2500kV of transmission lines above 230kV
- Supports generation with an aggregate capacity greater than 3000MW
- Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact

A medium impact BES Cyber System has one or more of the following characteristics:

- Supports generation with the aggregate capacity between 1500 – 3000MW
- Supports a sum between 1500 – 2500kV of transmission lines above 230kV
- Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more

A low impact BES Cyber System has one or more of the following characteristics:

- Supports a sum less than 1500kV of transmission lines above 230kV
- Supports transmission only between 110 – 230kV
- Supports generation with an aggregate capacity between 75 – 1500MW
- Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System
- Supports any Facilities that are designated a blackstart resource
- Supports any other RAS not already identified as a medium impact BES Cyber System

Likes 0

Dislikes 0

Response

The SDT appreciates your comments. The SDT is only authorized to address the TOCC issues as identified in the Standards Authorization Request for Project 2016-02. The SDT has revised criteria 2.12 to address the risk to the BES presented by the BES Cyber Systems that are capable of operating transmission.

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

No

Document Name	
Comment	
<p>NIPSCO is in support of the comment provided by EEI below.</p> <p>"The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.</p> <p>In addition, page 33 of the GTB states that "[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be changed to "In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s)." Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center."</p>	
Likes	0
Dislikes	0
Response	
Please see response to EEI comments.	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p>	

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0	
Dislikes 0	

Response

Please see response to EEI comment.

David Rivera - New York Power Authority - 3

Answer	No
Document Name	

Comment

The removal of the term “functional obligation” from 2.12 still does not clarify the requirement applies to TO because the capitalized term Control Center is used and that term implies functional registry (RC/BA/TOP/GOP). Clarification could be improved by using the non-capitalized term “control center” and defined as used in CIP-014. In addition, the use of the term “control” is also a source of confusion as it can be interpreted as having operational control (ie. Direct the switching operation) or physical control (perform the switching operation).

Likes 0

Dislikes 0

Response

The SDT asserts that using a weighting function based on the Transmission lines that a Control Center monitors and controls clarifies a Control Center that performs the reliability tasks of a TOP. Once this method was established, the SDT did not see a reason to modify the definition of Control Center to address the TOCC issue. The proposed weighting methodology adds clarity to the difference between medium impact BES Cyber Systems associated with a Control Center and low impact BES Cyber Systems associated with a Control Center.

Criterion 2.12 does not need to reference “functional obligation” to apply to TO’s, as the definition of Control Center encompasses all functional entities that perform the reliability tasks of RC/BA/TOP/GOP. It is not limited to functional entities registered as RC/BA/TOP/GOP.

Criterion 2.12 encompasses both the ability to direct actions and the capability to physically operate BES elements per the Control Center definition. The “monitoring” capability is the part that enables the direction of actions. The “control” capability is the part that enables the actual physical change to the BES element.

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy requests further clarification on the removal of the phrase “perform functional obligations of a TOP”. Was it the drafting team’s intent that all Control Centers, and not just Control Centers that perform TOP obligations, should be considered applicable to the new criterion? For instance, would a Control Center operated by a GO/GOP or a DP be considered under this criterion, even though any operation involving Transmission lines conducted by that Control Center, would only be done at the direction of a Transmission Operator? We would also like to point out that the use of “functional obligations” is also present when referencing the BA in 2.13. Lastly, the revision proposed to criterion 2.12 appears to create some inconsistency with the language used in the High Impact section, part 1.3.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. The SDT has revised criterion 2.12 to address the confusion related to the term “functional obligation,” as noted in the VTAG transfer document. To address the risk to the BES presented by the BES Cyber Systems that are capable of operating transmission, the revision is intended to address entities that perform tasks of operating transmission, regardless of registration. Research performed by the SDT did not show the same concern with the other Criteria.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMMPA

Answer

No

Document Name

2016-02_CIP-002-6_Unofficial_Comment_Form_10 27 17 draft- FMMPA.pdf

Comment

FMMPA appreciates the SDT efforts for clarifying the applicability requirements for a TO Control Center that performs the functional obligations of a TOP. We have some suggested language for Criterion 2.12 that we feel removes some ambiguity and possible interpretation questions. Our suggested language is as follows:

“Each BES Cyber System, not included in Section 1 above, associated with any of the following:”

“Cyber Assets used to control BES Transmission lines, located at Control Centers or backup Control Centers, where the summed weighted value (according to the table below) of each BES Transmission Line controlled or monitored exceeds 6000.”

Likes 0

Dislikes 0

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

Mark Gray - Edison Electric Institute (EEI) - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.

In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).” EEI is concerned that this statement might be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the SDT consider revised language similar to the following: “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment and asserts that the language in the GTB is consistent with the language in Attachment 1, Section 2. While the SDT agrees that the “associated with” language could be more precise, this language exists in the currently approved version of CIP-002, and addressing the “associated with” language is not related to the SDT’s currently proposed modifications to CIP-002.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 1 response.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Please see response to EEI comment.

Don Schmit - Nebraska Public Power District - 5

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

The new 2.12 criterion language has the Impact Rating on the “Control Center” as an asset, yet in the “Rationale for Criterion 2.12” on page 18 of the standard it has the “...aggregate weighted value for applicable BES Cyber Systems...”. This is a problem because there could be a case where the number of transmission lines being controlled from a Control Center (asset) add up to a weighted value 8000 but there are two completely separate control systems (applicable BES Cyber Systems) each controlling transmission lines that would add up to a weighted value of 4000. In this case the language of IRC would lead you to make both control systems Medium Impact as the asset is being rated. If the intent of the standard is to assign the aggregate weighted value to the BES Cyber Systems as the language in

the “Rationale for Criterion 2.12”, the two do not align and confuse the reader. The “Consideration of Issues and Directives” on the NERC project site also says that the “Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact.”. This leads the reader to believe the aggregate weighted value is associated with BES Cyber Systems, not the Control Center asset itself. We recommend the language of the standard and any rationale or guidance be made clear as to which one (the Control Center asset or the BES Cyber System) the aggregate weighted value is associated.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment and has modified the rationale to make it clear that the aggregated weighted value is associated with the Control Center.

David Jendras - Ameren - Ameren Services - 3

Answer

No

Document Name

Comment

We support comments offered by EEI for this question.

Likes 0

Dislikes 0

Response

Please see response to EEI comment.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes	0
Dislikes	0
Response	
The SDT notes that Southern California Edison did not comment on this question.	
Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities supports Cowlitz PUD and APPA comments	
Likes	0
Dislikes	0

Response	
The SDT notes that Cowlitz PUD and APPA did not comment on this question.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
<p>MidAmerica would like to change its answer for this question to NO.</p> <p>MidAmerican agrees with EEI's comments. Please see EEI's Comments below:</p> <p>The proposed revisions improve upon the clarity of the applicability of Criterion 2.12; however, the proposed criterion raises a number of issues, many of which are discussed in our response to question 2.</p> <p>In addition, page 33 of the GTB states that “[i]n accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s). This statement could be interpreted by an auditor as requiring that all systems controlled and monitored by a medium impact Control Center should also be rated as medium impact as well. For this reason, EEI suggests that the language be changed to “In accordance with Criterion 2.12, all BES Cyber Systems contained within four walls of a medium impact Control Center should be categorized as medium impact BES Cyber System(s).” Such a change would more clearly categorize the applicable assets while limiting an interpretation of the language to mean something outside or beyond the four walls of the medium impact Control Center.</p>	
Likes	0
Dislikes	0
Response	
Please see response to EEI comment.	
Barry Lawson - National Rural Electric Cooperative Association - 4	

Answer	Yes
Document Name	
Comment	
NRECA supports the modified Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	
The SDT thanks you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
The SDT notes that the Security Working Group (SWG) did not comment on this question.	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Salt River Project supports comments submitted by APPA.	
Likes	0
Dislikes	0
Response	
The SDT notes that APPA did not comment on this question.	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
MMWEC agrees that revisions to Criterion 2.12 clarify the issue of “functional obligation.” However, additional wording for Criterion 2.12 is needed to further clarify how Criterion 2.12 is to be applied. MMWEC supports APPA’s response to question 5 regarding this issue.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment and notes that APPA did not comment on this question.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	

Likes	0
Dislikes	0
Response	
The SDT notes that SRC+SWG did not comment on this question.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the Standard Drafting Team’s (SDT) approach to to replace the “functional obligation” language in CIP-002-5.1, Criteria 2.12 with a bright line 6000 weighted value for BES Transmission Line threshold for delineating Medium and Low Impact Control Centers.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment.	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	Yes
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	
Likes	0

Dislikes	0
Response	
The SDT notes that Cowlitz PUD and APPA did not comment on this question.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The group would like the drafting team to provide clarity on page 18 in reference to criteria 2.12 rationale. The third paragraph mention BES Cyber Systems and we feel that it should reference BES Transmission Lines instead.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment and has modified the rationale to make it clear that the aggregated weighted value is associated with the Control Center.	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have comments on Question 1.	
Likes	0
Dislikes	0

Response	
The SDT thanks you for your comment.	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
NRG requests that the drafting team to provide clarity on page 18 in reference to criteria 2-12 rationale. The third paragraph mentions BES Cyber Systems and NRG requests SDT consideration that it should reference BES Transmission Lines instead.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment and has modified the rationale to make it clear that the aggregated weighted value is associated with the Control Center.	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	

Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Lotz - City of Independence, Power and Light Department - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Ann Todd - Illinois Municipal Electric Agency - 4	
Answer	
Document Name	
Comment	
IMEA supports APPA comments.	

Likes 0	
Dislikes 0	
Response	
The SDT notes that APPA did not comment on this question.	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes 0	
Dislikes 0	
Response	

2. Criterion 2.12: The SDT modified CIP-002-5.1a Attachment 1, Criterion 2.12 to be similar to the construct used in Criterion 2.5. Do you agree with the SDT's approach in the modified criterion to evaluate a BES Cyber System's span of control by summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls? If not, please provide your rationale and an alternate proposal.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

The SDT notes that Robert Blackney did not comment on this question.

Spencer Tacke - Modesto Irrigation District - 4

Answer No

Document Name

Comment

Evaluation should be based on the short circuit MVA capacity at the element location in the system.

Likes 0

Dislikes 0

Response

Thank you for your comment. Anticipating that many Responsible Entities have a large number of Transmission Lines, the SDT has established a table of weighted values to simplify the evaluation. The values are estimates based on data found in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.”

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

We believe the control center should have the same rating as the highest impact rating of the transmission facilities that it monitors. Example, if a control center monitors high impact transmission facilities, then it should also have a high impact rating. If a control center monitors only low or medium impact transmission facilities, then it should also have a low or medium impact rating, respectively.

Likes 0

Dislikes 0

Response

The SDT notes that there are no high impact Transmission Facilities. If the Control Center is monitoring higher impact Transmission Facilities, as noted in Attachment 1 criterion 1.3, that Control Center would be high impact. However, the modification made to criterion 2.12 is to address the Control Center that do not meet criterion 1.3, making them medium or low impact based on the Transmission Facilities the Control Center monitors and/or controls.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer No

Document Name

Comment

KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 2 response.

Likes 0

Dislikes 0

Response

Please see response to EEI comment.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

EEI cannot support the modified criterion and weighted value used in Criterion 2.12 at this time for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. *(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)*
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

For these reasons, EEI asks the SDT to consider other approaches such as limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” Contained within this recommendation is a suggestion that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we suggest that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

We submit that the above recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes 1	PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Nicolas Turcotte - Hydro-Quebec TransEnergie - 1

Answer	No
Document Name	

Comment

The formulation of the question #2 in the answer form is incorrect by inducing the notion of BCS whereas criterion 2.12 of the standard does not mention it. In our view, including the notion of BCS in the determination of the BES transmission lines to be included in the weighted voltage level calculation with a threshold of 6000 would allow an arbitrary division of an entity that would like to subtract from the requirement. We believe that criterion 2.12 as written in version 6 is correct and that the question of the form should be reworded in this way or at least that the respondent indicates No and specifies its answer in the comment section of the question # 2.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. The SDT contends that Criterion 2.12 is written to evaluate the Control Centers. Once the Control Centers meeting the criterion are identified, then the BES Cyber Systems are identified and categorized as appropriate. This is in keeping with each criteria in Attachment 1. The current Criterion 2.12 does not address BES Cyber System categorization based on the span of control of BES Cyber System(s), but instead on functional registration. This has shown to be a problem with Criterion 2.12 that warranted correction.

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer No

Document Name

Comment

Not all entities controlling lower voltage transmission, which ultimately serve a large customer population, should be allowed to move from medium to low impact for their control centers. Under the proposed criteria, INDN which provides utility services to over 100,000 residents would go from a medium to low impact control center. The low impact CIP requirements are not adequate protections for some entities.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment, but asserts that the 6000 aggregate weighted value established in proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 adequately categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each rating. The SDT sought to clarify Criteria 2.12 to ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that proposed Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

MEC disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. *(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)*
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

For these reasons, MEC recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes	0
Dislikes	0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	No
Document Name	
Comment	

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1**Answer**

No

Document Name**Comment**

NIPSCO is in support of the comment provided by EEI below.

"

EEI disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:

1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection.
2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. *(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)*
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

For these reasons, EEI recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value "exceeding 6000" with a range "exceeding 2500 but below 3000." We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we

recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact."

Likes	1	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla
-------	---	---

Dislikes	0	
----------	---	--

Response

Please see response to EEI comments.

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	No
--------	----

Document Name	
---------------	--

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the methodology described in the response to Question 1.

Likes	0	
-------	---	--

Dislikes	0	
----------	---	--

Response

Please see response to question 1.

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer	No
Document Name	
Comment	
<p>No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.</p>	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
<p>Dominion Energy disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:</p> <ol style="list-style-type: none"> 1. The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection. There is no methodology provided that demonstrates how the value is derived. 	

2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), appears to focus on the number of lines rather than facility impacts. This appears to create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.
3. The proposed Criterion 2.12 does not consider or exempt radial feeders.

Dominion Energy recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and in addition to providing the methodology for the derivation of the value, replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

These recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
<p>NRG has a concern that there may be confusion on what the drafting team’s intent is in reference to proposed language pertaining to BES Cyber System’s span of control instead of the BES Cyber System monitors and controls. Industry interpretation of the current language leads NRG stakeholders to believe that the Rationale information may not match up correctly with the CIP-002-6 Standard. (NRG requests clarity on the operation authority versus capability). NRG requests that the drafting team provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.</p> <p>Question: Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element? Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations? It seems that most if not all TOPs are Medium and this can reduce them to Low which may be a concern for the industry.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT thanks you for your comment. Please note that the language, “span of control” is not in the language of the Criterion, it is used to help explain the difference between the functional registration and the Transmission monitoring and control services the Control Center can perform.</p>	

In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer Yes

Document Name

Comment

SNPD agrees with the SDT's approach in using the "aggregated weighted values" per line and per voltage class to determine the Impact Ratings of Control Centers and Backup Control Centers.

When the aggregated weighted value of lines for each of the applicable voltage classes exceeds 6000 points, both the Control Center and the Backup Control Center whose Facilities are rated Medium Facilities, and all BES Cyber Systems that are part of the Control Centers should also be rated Medium Impact by association. However, the new terminology, that was adopted by the SDT, "**BES Cyber System's Span of Control**", is somewhat ambiguous. Is this concept related to evaluating the applicability of the BES Reliability Operating Services (BROS)?

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. Please note that the language, "span of control" is not in the language of the Criterion, it is used to help explain the difference between the functional registration and the Transmission monitoring and control services the Control Center can perform.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name**Comment**

The SPP Standards Review Group has a concern that there is confusion on what the drafting team's intent is in reference to proposed language pertaining to BES Cyber System's span of control instead of the BES Cyber System monitors and controls. Our interpretation of the current language leads us to believe that the Rationale information doesn't match up correctly with the CIP-002-6 Standard. (need clarity on the operation authority versus capability). We would ask the drafting team to provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.

Question:

Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element?

Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations?

It seems that most if not all TOP are Medium and this can reduce them to Low. This is a concern.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. Please note that the language, "span of control" is not in the language of the Criterion, it is used to help explain the difference between the functional registration and the Transmission monitoring and control services the Control Center can perform.

In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
<p>The term Transmission Line as defined in the Glossary of Terms Used in NERC Reliability Standards does not adequately identify the endpoints of a Transmission Line. Does the Transmission Line begin and end at the circuit breaker, line switch, or at the bus? A clarification of this issue would help Responsible Entities determine how to count lines in certain configurations, such as tapped lines. Additionally, are Responsible Entities required to count a Transmission Line if they only control the breakers on one end of the line, such as a tie line with a neighboring TOP?</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for your comment. The SDT has added further clarification in the Guidelines and Technical Basis providing examples of several Transmission Line configurations. This includes a discussion of multiple-point and multiple-tapped lines. The SDT asserts that operating a breaker on one end of a Transmission Line would constitute control of that line as the Responsible Entity has the ability to permit or disrupt the flow of current along that Transmission Line.</p>	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	Yes
Document Name	
Comment	
<p>Seattle City Light supports the comments of Cowlitz PUD and APPA.</p>	
Likes	0
Dislikes	0

Response	
Please see responses to Cowlitz PUD and APPA.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	
Likes	0
Dislikes	0
Response	
The SDT notes that SRC + SWG did not comment on this question.	
Jack Cashin - American Public Power Association – 4	
Answer	Yes
Document Name	
Comment	
<p>APPA agrees that SDT’s approach of “summing the weight value of each BES Transmission Lines that the BES Cyber System monitors and controls” is the desired approach. However, this is not what Criterion 2.12 requires (see answer to question 5 below). As written, Criterion 2.12 sums the BES Transmission Lines that the Control Center monitors and controls.</p>	
Likes	5
Dislikes	0
	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

David Gordon - Massachusetts Municipal Wholesale Electric Company - 5

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

MMWEC supports comments submitted by APPA.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Please see response to APPA.

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

Salt River Project supports comments submitted by APPA.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Please see response to APPA.

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
The SDT notes that Security Working Group (SWG) did not comment on this question.	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
<p>Agree with the weighting concept however, consider the following:</p> <ol style="list-style-type: none"> 1. Assuming wording became specific to TOs, should there be a caveat noting the transmission Facilities need to be at two or more locations similar to the existing Control Center definition with respect to TOP? This would exclude TOs that operate one large station. 2. Assuming wording became specific to TOs there should be a weighting for 500 KV and above. Criterion 1.3 would apply to Control Center (TOP registration) that control 500 kV+ lines (criterion 2.4); if 2.12 were specific to TOs, then a weight should be given to the 500 kV+ lines. If the intention is for a TO's control center that "operates" a 500 kV+ facility to be High impact, then clarification is needed in criterion 1.3; if the intention is that TO control centers would, at most, be classified as Medium impact, then a weighting is needed for the 500 kV+ lines in criterion 2.12. 	

Likes	0
Dislikes	0
Response	
<p>The SDT thanks you for your comments. The SDT contends that if a Control Center monitors or controls Transmission at a single station that meets Criterion 2.12, it should be considered medium impact. The SDT notes that Criterion 1.3, would still be relevant as a high impact Control Center. If the Transmission Control Center does not meet Criterion 1.3, it should then be evaluated under Criterion 2.12.</p>	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
<p>NRECA supports weighted value approach in the modified Criterion 2.12.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT thanks you for your comment.</p>	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
<p>Cowlitz PUD agrees with the intent of the SDT as implied in Question 2. However, as written, Criterion 2.12 appears to require an evaluation of the Control Center’s span of control rather than the BES Cyber System associated with the Control Center. Please see response to Question 5.</p>	

Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
MidAmerica would like to change its answer for this question to NO.	
MidAmerican agrees with EEI's comments. Please see EEI's Comments below:	
EEI disagrees with modified criterion and weighted value used in Criterion 2.12 for the following reasons:	
<ol style="list-style-type: none"> 1. The use of an aggregate weighted value of 6000 contains no justified rational and appears to be an arbitrary selection. 2. The proposed criterion approach, which deviates from the facilities-based approach used to identify high impact Control Centers (i.e., those monitoring and controlling medium impact facilities), focuses more on the number of lines rather than facility impacts. <i>(EEI is concerned that the proposed Criterion 2.12 could create situations where control centers that simply monitor a large number of lower impact transmission lines (i.e., 24 or more - 100kV to 199kV lines) will be classified as medium impact while other Control Centers that are monitoring and controlling a small number of higher impact transmission lines (i.e., 300kV to 499kV and 200kV to 299kV lines) could be classified as low impact.)</i> 3. The proposed Criterion 2.12 does not consider or exempt radial feeders. 	

For these reasons, EEI recommends that the SDT consider limiting the voltage range for medium impact Control Centers to 200kV, similar to Criterion 2.5, and replacing the aggregate weighted value “exceeding 6000” with a range “exceeding 2500 but below 3000.” We also recommend that Criterion 2.12 use the same table and methodology as provided in Criterion 2.5 since a similar approach would provide greater focus and emphasis on identifying those facilities which are most likely to have the greatest impact on BES reliability. Lastly, we recommend that if a Control Center only monitors and controls BES Transmission Lines within the range of 100kV to 199kV, then it should be considered a Low Impact Control Center.

Our recommendations more closely leverage Criterion 2.5 and provide greater consistency, which is more likely to result in the identification of higher impact Control Centers through the use of a lower “aggregate weighted value.” Moreover, Control Centers that fell just outside of the parameters used to identify high impact Control Centers would be categorized as Medium Impact with this approach. This recommended approach also does not inappropriately pull in a disproportionate number of Control Centers that are simply monitoring lower voltage transmission lines. The rationale for the proposed aggregate weighted value between 2500 to 2999 is that Control Centers monitoring and controlling transmission facilities with two connected 345kV lines or four connected 230kV lines at a transmission station or substation would be categorized as Medium Impact.

Likes	0
-------	---

Dislikes	0
----------	---

Response

Please see response to EEI comments.

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes	0
-------	---

Dislikes	0
----------	---

Response	
Please see response to Cowlitz PUD and APPA comments.	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
N&ST assumes, based on the precise wording of Criterion 2.12, that what must be evaluated is a <i>Control Center's</i> span of control, vs. any particular BES Cyber System associated with a Control Center, and that if a Control Center meets this criterion, <i>all</i> of its associated BES Cyber Systems must be categorized as medium impact.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment and agrees with the assumptions made.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Seminole agrees that this is a valid approach as long as Functional Registrations are honored.	
Likes	0
Dislikes	0
Response	

Proposed Criterion 2.12 is applicable to all BES Cyber Systems associated with Control Centers (regardless of functional registration), not included in High Impact Rating (H) that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the associated table.

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson

Answer Yes

Document Name

Comment	
Likes	0
Dislikes	0
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	

Comment	
Likes	0
Dislikes	0
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jim Nail - City of Independence, Power and Light Department - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name
Southern Company

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes 0	
Dislikes 0	
Response	

Mary Ann Todd - Illinois Municipal Electric Agency - 4	
Answer	
Document Name	
Comment	
IMEA supports APPA comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to APPA comments.	

3. Criterion 2.12: Do you agree with the 6000 aggregate weighted value that is used in Criterion 2.12 to establish the minimum threshold for medium impact BES Cyber Systems associated with Control Centers that monitor and control Transmission? If not, please provide your rationale and an alternate proposal.

Jim Nail - City of Independence, Power and Light Department – 5

Answer No

Document Name

Comment

As written, there will be TOP Control Centers that will drop from Medium to Low and become exempt from many of the current requirements. Given the propensity for NOT maintaining standards of performance which are not enforced/required, this WILL produce a predictable weakening of the BES's overall Cyber-Security posture.

Likes 0

Dislikes 0

Response

In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

Dominion Energy does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Jeanne Kurzynowski - Consumers Energy Company - 1 – RF

Answer

No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Hien Ho - Tacoma Public Utilities (Tacoma, WA) – 4

Answer

No

Document Name

Comment	
<p>Tacoma Power proposes that the aggregate weighted value be 30000 instead of 6000. The proposed weighting values overestimates the impact of 115 kV subtransmission networks. For example, between two of our major substations we have a line rated at 239 MW with 4 intermediate looped through distributions stations. In the proposed evaluation methodology each of the short sections between substations would be weighted as 250 for a total value of 1250, overstating the importance of the line by more than a factor of 5.</p> <p>An alternative to adjusting the threshold would be to exclude any line that terminates at a substation that only has two transmission lines connected.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT appreciates your comments, but asserts that the misuse of BES Cyber Systems that are associated with Control Centers that monitor and control a considerable number of BES Transmission Lines in the 100 to 199 kV range could impact the reliability of the Bulk Electric System. <i>The SDT has revised the Guidelines and Technical Basis of proposed Reliability Standard CIP-002-6 to address Transmission Line configurations. Consistent with the GTB for criterion 2.5, multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line.</i></p>	
Wendy Center - U.S. Bureau of Reclamation – 5	
Answer	No
Document Name	
Comment	
<p>Reclamation recommends simplifying the Impact Rating Criteria using the methodology described in the response to Question 1.</p>	
Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. The SDT is only authorized to address the TOCC issues as identified in the Standards Authorization Request for Project 2016-02.

Steve Toosevich - NiSource - Northern Indiana Public Service Co. – 1

Answer

No

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"EEI does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2."

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the

misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES .

James Anderson - CMS Energy - Consumers Energy Company – 1

Answer No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Karl Blaszkowski - CMS Energy - Consumers Energy Company – 3

Answer No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT asserts that if a BES Cyber System associated with a Control Center has been categorized as high impact, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers, if the BES Cyber Systems associated with the Control Centers were already categorized as high impact.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer No

Document Name

Comment

Suggest 3000 points to be in-line with Criterion 2.5. Concerns that entities with large amounts of 100-199kV lines would be excluded (6000 points = 24 100kV lines).

Likes 0

Dislikes 0

Response

The SDT appreciates your comment, but contends that proposed Criterion 2.12 adequately categorizes BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT used Criterion 2.5 as a basis for developing proposed Criterion 2.12. In Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled this value to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls BES Transmission Lines.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. – 1

Answer

No

Document Name

Comment

MEC does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer	No
Document Name	

Comment

The aggregate weighted value of 6000 is too high for entities controlling lower voltage transmission ultimately serving a large customer population. Under the proposed criteria, INDN which provides utility services to over 100,000 residents would go from a medium to low impact control center. The low impact CIP requirements are not adequate protections for some entities.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment, but asserts that the 6000 aggregate weighted value established in proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 adequately categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each rating. The SDT sought to clarify Criteria 2.12 to ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that proposed Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

No

Document Name

Comment

EI cannot support the 6000 aggregate weighted value used in Criterion 2.12 at this time for the reasons specified in our response to question 2.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index." The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES .

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	
Comment	
KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 3 response.	
Likes 0	
Dislikes 0	
Response	
<p>The SDT thanks you for your comments.</p> <p>In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.</p> <p>The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple BES Transmission Lines in the 100 to 199 kV voltage class could impact the reliability of the Bulk Electric System and require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.</p>	

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders can be excluded in Exemption 1 of the Bulk Electric System definition.

The SDT appreciates your proposed revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in this voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES .

David Jendras - Ameren - Ameren Services – 3

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

See the response to question 2 above.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

The SDT appreciates your comments, but contends that categorizing BES Cyber Systems associated with a Control Center by matching the impact rating of the highest Transmission Facility that it controls would not sufficiently categorize the BES Cyber System based on its span of control. Additionally, there are no high impact Transmission Facilities, so the proposed approach would shift all high impact BES Cyber Systems used by and located at Control Centers to a medium impact rating.

Kenya Streeter - Edison International - Southern California Edison Company – 6

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

The SDT verified that Robert Blackney did not submit a comment for Question 3.

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

No comment provided by commenter.

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer

Yes

Document Name

Comment

Co lorado Srings Utilitiessupports Cowlitz PUD and APPA comments

Likes 0

Dislikes	0
Response	
The SDT appreciates your comment and asserts that the aggregate weighted value, as detailed in proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12, consists of the summation of the weighted values of the BES Transmission Lines that are monitored and controlled collectively by the BES Cyber System(s) associated with a Responsible Entity's Control Center.	
Russell Noble - Cowlitz County PUD – 3	
Answer	Yes
Document Name	
Comment	
Cowlitz PUD agrees the aggregated weighted value will properly identify the impact threshold of a BES Cyber System as long as the calculated <i>value</i> relates directly to those Transmission Lines the BES Cyber System <i>monitors and controls</i> .	
Likes	5
Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long	
Dislikes	0
Response	
The SDT appreciates your comment and asserts that the aggregate weighted value, as detailed in proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12, consists of the summation of the weighted values of the BES Transmission Lines that are monitored and controlled by the BES Cyber System(s) associated with a Responsible Entity's Control Center.	
Barry Lawson - National Rural Electric Cooperative Association – 4	
Answer	Yes
Document Name	
Comment	

NRECA supports the 6000 aggregate weighted value used in Criterion 2.12.

Likes 0

Dislikes 0

Response

The SDT thanks you for your support.

David Rivera - New York Power Authority – 3

Answer

Yes

Document Name

Comment

Agree with the weighting concept however, consider the following:

1. Assuming wording became specific to TOs, should there be a caveat noting the transmission Facilities need to be at two or more locations similar to the existing Control Center definition with respect to TOP? This would exclude TOs that operate one large station.
2. Assuming wording became specific to TOs there should be a weighting for 500 KV and above. Criterion 1.3 would apply to Control Center (TOP registration) that control 500 kV+ lines (criterion 2.4); if 2.12 were specific to TOs, then a weight should be given to the 500 kV+ lines. If the intention is for a TO's control center that "operates" a 500 kV+ facility to be High impact, then clarification is needed in criterion 1.3; if the intention is that TO control centers would, at most, be classified as Medium impact, then a weighting is needed for the 500 kV+ lines in criterion 2.12.

Likes 0

Dislikes 0

Response

The SDT appreciates your comments, but does not intend to limit the scope of Criterion 2.12 to Transmission Owners. The proposed criterion is meant to apply to any Control Center, as defined in the NERC Glossary of Terms, that monitors and controls applicable BES Transmission Lines, regardless of registration. Additionally, the SDT asserts that Criterion 1.3 does not apply only to Responsible Entities that are registered as Transmission Operators. Criterion 1.3 applies to any Responsible Entity that performs the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

Richard Vine - California ISO – 2

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

The SDT verified that the SWG did not provide a comment for Question 3.

Lona Calderon - Salt River Project - 1,3,5,6 – WECC

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

Salt River Project supports comments submitted by APPA.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

The SDT verified that APPA did not provide a comment for Question 3.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2

Answer Yes

Document Name

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response

The SDT verified that the SRC and SWG did not provide a comment for Question 3.

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECE & Member G&Ts

Answer Yes

Document Name

Comment

Does Criterion 2.12 allow a Responsible Entity to mitigate risk to the BES by separating its monitoring and control functions at a Control Center into multiple separate BES Cyber Systems? For example, a Responsible Entity monitors and controls Transmission Lines that sum to an aggregate weighted value of 7000, but they split the monitoring and control functions between two BES Cyber Systems (3500 each) that reside in two separate ESPs. This option reduces the risk to the reliability of the BES if a system is compromised. Does this allow the BES Cyber Systems associated with the Control Center in this example to be categorized as low impact BES Cyber Systems?

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. Proposed Criterion 2.12 describes a Control Center that monitors and controls BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the associated table in proposed Criterion 2.12. Segmentation of a BES Cyber System into separate systems doesn't result in a reduction in impact rating of the BES Cyber Systems because they are associated with the same Control Center.

Long Duong - Public Utility District No. 1 of Snohomish County – 1

Answer Yes

Document Name

Comment

SNPD does not have comments on Question 3.

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMMPA</p>	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0

Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
<p>Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham</p>	
Answer	
Document Name	
Comment	
<p>MidAmerica would like to change its answer for this question to NO.</p> <p>MidAmerican agrees with EEI's comments. Please see EEI's Comments below:</p> <p>EEI does not support the 6000 aggregate weighted value used in Criterion 2.12 for the reasons specified in our response to question 2.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT thanks you for your comments. Please see the SDT's response to EEI's comments.</p>	
<p>Mary Ann Todd - Illinois Municipal Electric Agency – 4</p>	
Answer	
Document Name	
Comment	

IMEA supports APPA comments.	
Likes	0
Dislikes	0
Response	
The SDT verified that APPA did not provide a comment for Question 3.	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes	0
Dislikes	0
Response	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	
The SDT elected to double weighted value used to define Medium Impact substations in Criterion 2.5. While this may be a reasonable approach, the Texas RE requests the SDT provide a basis for this approach, including why the Control Center weighted value bright line	

should be higher than that used for the Transmission Facility criterion set forth in 2.5. In addition, Texas RE requests clarification on how double circuits are calculated as it is assumed they are calculated as a single line.

Likes 0

Dislikes 0

Response

In Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled this value to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT considers double circuits to be a single Transmission Line and has modified the Guidelines and Technical Basis of proposed Reliability Standard CIP-002-6 to provide further clarity.

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

The SDT appreciates your comment. Please refer to the SDT's response to Cowlitz PUD's comment.

4. Criterion 2.12: The SDT modified Criterion 2.12 to categorize BES Cyber Systems associated with Control Centers that monitor and control Transmission regardless of a Responsible Entity’s functional registration. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

Long Duong - Public Utility District No. 1 of Snohomish County – 1

Answer No

Document Name

Comment

SNPD suggests that a Control Center that is only responsible for Low Impact Facilities, should default to a Low Impact Control Center rating; independent of its registration or weighted value criterion. Currently, there are numerous Medium Impact Control Centers that meet the registration requirements or proposed weighting criteria, but clearly do not have BES Cyber Assets.

“A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.”

Registered Entities have identified SCADA related assets and systems as BCS and BCAs in order to comply with Reliability Standards interpretations and the expectations of the regulators. However, if these assets were rendered unavailable, degraded, or misused, they would not adversely impact the Bulk Electric System. In these cases the scope of the impact would be local load service and restoration efforts. They would not result in BES cascading events. The original intent of the NERC Reliability Standards were to address BES reliability, yet the application of Medium Impact Control Centers operating Low Impact Facilities often targets local load service and distribution systems.

Likes 0

Dislikes 0

Response

The SDT appreciates your suggested revisions, but contends that they do not adequately categorize BES Cyber Systems associated with Control Centers that monitor and control a considerable number of BES Transmission Lines. Industry comments and historical events indicate that BES Transmission Lines in the 100 – 199 kV voltage class can impact the reliability of the BES and the SDT asserts that proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 categorizes applicable BES Cyber Systems commensurate with their risk to the reliability of the BES.

Kenya Streeter - Edison International - Southern California Edison Company – 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

The SDT verified that Robert Blackney did not provide a comment for Question 4.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA

Answer No

Document Name

Comment

We agree with the described concept of categorizing BES Cyber Systems but would want to see the suggested language used from our comments for Question 1.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. After considering the proposed revisions (from commenter), the SDT has decided to retain the language in proposed Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 because it is based on the Control Center. This approach is consistent with the rest of the criteria in Attachment 1.

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer No

Document Name

Comment

See our response to question 1. Does this question confirm that the drafting team’s intent is that all Control Centers should be considered under this criterion, notwithstanding the fact that in order to control Transmission facilities (100kV and above), a NERC BA/TOP certification is required?

Likes 0

Dislikes 0

Response

Proposed Criterion 2.12 is applicable to all BES Cyber Systems associated with Control Centers (regardless of functional registration), not included in High Impact Rating (H), that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the associated table.

David Rivera - New York Power Authority – 3

Answer No

Document Name	
Comment	
<p>The approach does not clarify the issue. The removal of the term “functional obligation” from 2.12 still does not clarify the requirement applies to TO because the capitalized term Control Center is used and that term implies functional registry (RC/BA/TOP/GOP). Clarification could be improved by using the non-capitalized term “control center” and defined as used in CIP-014. In addition, the use of the term “control” is also a source of confusion as it can be interpreted as having operational control (ie. Direct the switching operation) or physical control (perform the switching operation).</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT asserts that using a weighting function based on the Transmission lines that a Control Center monitors and controls clarifies a Control Center that performs the reliability tasks of a TOP. The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012. The proposed weighting methodology adds clarity to the difference between medium impact BES Cyber Systems associated with a Control Center and low impact BES Cyber Systems associated with a Control Center.</p> <p>Criterion 2.12 does not need to reference “functional obligation” to apply to TO’s, as the definition of Control Center encompasses all functional entities that perform the reliability tasks of RC/BA/TOP/GOP. It is not limited to functional entities registered as RC/BA/TOP/GOP.</p> <p>Criterion 2.12 encompasses both the ability to direct actions and the capability to physically operate BES elements per the Control Center definition. The “monitoring” capability is the part that enables the direction of actions. The “control” capability is the part that enables the actual physical change to the BES element.</p>	
Karl Blaszkowski - CMS Energy - Consumers Energy Company – 3	
Answer	No
Document Name	
Comment	

No Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation – 5	
Answer	No
Document Name	
Comment	
Reclamation recommends that impact ratings apply to BES Cyber Systems associated with Transmission (Control Center or control room) or generation (Control Center, control room, or plant), or any identified Facilities regardless of a Responsible Entity’s functional registration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT asserts that CIP-002-6, Attachment 1 consists of a categorization process that focuses on a BES Cyber System's span of control and its associated risk to the reliability of the Bulk Electric System. The proposed revision to Criterion 2.12 is based solely on a BES Cyber Systems span of control over BES Transmission Lines, regardless of functional registration.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Section 2.12 of the proposed standard conflicts with the Applicability section of the standard. Under criterion 2.12, Distribution Provider control centers could be applicable, but Distribution Providers are not included as applicable entities. The Applicability section should be the ultimate deciding factor for determining applicability. In addition, we recommend the removal of the first line in the table.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. The SDT assumes that entities operating BES Transmission Lines would be registered as either a TO or TOP.

The first line of the table is provided to reinforce that non-BES facilities are not included in proposed Criterion 2.12.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer

No

Document Name

Comment

The Proposed Definition of Control Center would have direct bearing on the outcome of how Xcel Energy interprets this question. The term would have to be finalized before an opinion could be formed.

Likes 0

Dislikes 0

Response

The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 – FRCC

Answer

No

Document Name

Comment

Per the registration criteria, Transmission Operators are “responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.” As a result, this responsibility falls on directly on Transmission Operators. Further expansion of the criterion places responsibilities on Transmission Owners for activities they are not registered for.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments. CIP-002-5.1a is a Critical Infrastructure Protection standard that requires Responsible Entities to perform a categorization of their BES Cyber System(s). BES Cyber System categorization is based on the span of control of BES Cyber System(s), not functional registration. Transmission Owners are currently required to determine if they perform the functional obligation of a Transmission Operator under Criterion 2.12. Any Transmission Owner that operates BES Cyber System(s), associated with a Control Center, that can functionally control BES Transmission Facilities at one or more locations should be identified as medium impact in accordance with Criterion 2.12. The proposed Criterion 2.12 attempts to provide further clarity to TOs through a bright line approach and does not expand beyond the current scope of Criterion 2.12.

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	Yes
Document Name	
Comment	
AECI agrees with the approach and believes that a BES Cyber System (BCS) should be categorized by the BCS's span of control, regardless of functional registration.	
Likes 0	
Dislikes 0	
Response	
The SDT thanks you for your comments.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the SRC comment.	
Lona Calderon - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

The SDT verified that APPA did not provide a comment for Question 4.

Richard Vine - California ISO – 2

Answer

Yes

Document Name

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Please see the response to the SRC comment.

Barry Lawson - National Rural Electric Cooperative Association – 4

Answer

Yes

Document Name

Comment

NRECA supports this approach.

Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment.	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Any entity that controls Transmission service that could impact the overall grid reliability, capability, and the functionality of power delivery should be following the CIP security structure in monitoring, maintaining and reporting on those systems that have physical control capability.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Agree. However would be clearer if the statement "...regardless of a Responsible Entity's functional registration" was included in criteria 2.12.	

Likes	0	
Dislikes	0	
Response		
The SDT appreciates your comments, but contends that the proposed revision wouldn't be consistent with the existing criteria and would require further changes within CIP-002-5.1a.		
Russell Noble - Cowlitz County PUD - 3		
Answer	Yes	
Document Name		
Comment		
Cowlitz PUD is in agreement as long as the definition of "Control Center" is modified to clearly point to registered functions, including Transmission Owners.		
Likes	5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes	0	
Response		
The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012.		
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities		
Answer	Yes	
Document Name		
Comment		
Colorado Springs Utilities supports Cowlitz PUD and APPA comments		

Likes	0
Dislikes	0
Response	
The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012.	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. – 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association – 4	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	

Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec TransEnergie – 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Lotz - City of Independence, Power and Light Department - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. – 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Toosevich - NiSource - Northern Indiana Public Service Co. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Austin - AEP – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA – 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power – 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC – 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department – 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	

Likes 0	
Dislikes 0	
Response	
The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012.	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes 0	
Dislikes 0	
Response	
Mary Ann Todd - Illinois Municipal Electric Agency – 4	
Answer	
Document Name	
Comment	
IMEA supports APPA comments.	
Likes 0	
Dislikes 0	
Response	

The SDT verified that APPA did not provide a comment for Question 4.

Jeanne Kurzynowski - Consumers Energy Company - 1 – RF

Answer

Document Name

Comment

No comment.

Likes 0

Dislikes 0

Response

5. Criterion 2.12: Do you agree with the proposed modifications to Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer No

Document Name

Comment

See response to Question 4.

Likes 0

Dislikes 0

Response

Jim Nail - City of Independence, Power and Light Department - 5

Answer No

Document Name

Comment

As written, there will be TOP Control Centers that will drop from Medium to Low and become exempt from many of the current requirements. Given the propensity for NOT maintaining standards of performance which are not enforced/required, this WILL produce a predictable weakening of the BES's overall Cyber-Security posture.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer No

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes 0

Dislikes 0

Response

Please see response to Cowlitz PUD and APPA comments.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

Based on the response to Question 4, Dominion Energy recommends the following additional language modification.

“TO and TOP Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 2500 but below 3000 according to the table below. The "aggregate

weighted value" for a TO or TOP Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center."

Likes 0

Dislikes 0

Response

The SDT appreciates your comments.

In Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station/substation. The SDT doubled this value to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

The SDT asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT also asserts that the misuse of BES Cyber Systems that are associated with Control Centers that control multiple Transmission Lines in the 100 to 199 kV could impact the reliability of the Bulk Electric System and would require a medium impact classification. BES Cyber Systems used by and located at Control Centers that perform the functional obligations of the Transmission Operator for one or more of the ("higher impact") assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 are already categorized as high impact BES Cyber Systems in Criterion 1.3.

The SDT asserts that Criterion 2.12 considers radial feeders exempt from classification. The proposed criterion uses the phrase BES Transmission Lines to include only those Transmission Lines that are identified in the Bulk Electric System definition. Radial feeders would be excluded in Exemption 1 of the Bulk Electric System definition.

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer

No

Document Name	
Comment	
<p>No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.</p>	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
<p>Reclamation recommends simplifying the Impact Rating Criteria using the methodology stated in the response to Question 1.</p>	
Likes 0	
Dislikes 0	
Response	

Please see response to question 1.	
Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
NIPSCO is in support of the comment provided by EEI below. "See our comments, rationale and alternate proposal as provided in our response to question 2."	
Likes	0
Dislikes	0
Response	
Please see response to EEI comments.	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0

Dislikes	0
Response	
<p>The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.</p>	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
<p>For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.</p> <p>An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.</p>	
Russell Noble - Cowlitz County PUD - 3	
Answer	No

Document Name	
Comment	
<p>Cowlitz PUD fully supports establishment of medium and low impact TOP/TO Control Centers, and believes that summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls is the desired approach. However, it is possible that Criterion 2.12 can be interpreted by the Regional Entity contrary to this approach. As written, Criterion 2.12 appears to mandate a “Control Center impact designation” by summing the weighted values of Transmission Lines that the Control Center monitors and controls via any methodology. Cowlitz PUD has obtained confirmation from regional compliance personnel opinion in this regard. Monitoring and control can include Control Center operator verbal communication with field personnel, or non-programmable electronic devices <i>along with</i> BES Cyber Assets. The result is the BES Cyber System is not categorized by evaluating its integral importance to the BES asset’s function, it is categorized based on mere association with the asset regardless of whether it is necessary for the asset’s complex function.</p> <p>Cowlitz PUD supports the APPA suggested alternate proposal.</p>	
Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
<p>The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.</p>	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

See our comments, rationale and alternate proposal as provided in our response to question 2.

Likes 0

Dislikes 0

Response

Please response to question 2.

David Rivera - New York Power Authority - 3

Answer

No

Document Name

Comment

Removing functional obligation does not remove the conflict with the existing definition of Control Center for performing the functional obligation of a TOP. Removing Control Center and replacing with the control center concept used in CIP-014 would provide clarification.

Likes 0

Dislikes 0

Response

The SDT asserts that utilizing a weighting function based on the Transmission lines that a Control Center monitors and controls clarifies a Control Center that performs the functional obligation of a TOP. The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012. The weighting methodology proposed adds clarity to the difference between a Control Center containing Medium Impact BES Cyber Systems, and a Control Center containing Low Impact BES Cyber Systems

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

No

Document Name

Comment

IID believes that summing the weighted value of each BES Transmission Line that the BES Cyber System monitors and controls is the desired approach, but Criterion 2.12 can be interpreted by the Regional Entity contrary to this approach. As written, Criterion 2.12 appears to mandate a “Control Center impact designation” by summing the weighted values of Transmission Lines that the Control Center monitors and controls via any methodology. Monitoring and control can include Control Center operator verbal communication with field personnel, or non-programmable electronic devices along with BES Cyber Assets. The result is the BES Cyber System is not categorized by evaluating its integral importance to the BES asset’s function, it is categorized based on mere association with an asset regardless of whether it is necessary for the asset’s complex function.

Further, IID has concerns a Control Center that may be used for various functions, and may have several isolated BES Cyber Systems (BCS) to cover each. In addition, applicable entities should be encouraged to apply technology which is not subject to the inherent vulnerabilities of programmable devices using routable protocol. Removal of key high risk control to highly secure technology should be removed from the “aggregate weighted value” of the BES Cyber Systems used to monitor and control.

IID supports the following possible modifications:

1. At the beginning of Section 2: Each BES Cyber System, not included in Section 1 above, integral in the operation of the following:
2. For Rational for criterion 2.12, last paragraph, second sentence: ... “weight value per line” shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center’s or backup Control Center’s BES Cyber System...
3. For criterion 2.12: Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center’s or backup Control Center’s BES Cyber System.

Likes 0

Dislikes 0

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems. In the case where isolated BES Cyber Systems are present for various functions, Criteria 2.12 clearly applies to the monitoring and controlling of transmission lines. BES Cyber Systems associated with other functions would need to be assessed as appropriate by the Responsible Entity based on the other criteria set forth throughout Attachment 1.

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer	No
Document Name	
Comment	
<p>The proposed changes to criterion 2.12 will allow some entities, currently rated at medium impact, to change their control center(s) impact rating to low. This change could significantly increase both cyber and physical risks to reliability for the entity moving to low, and also the entities they are connected to. The low impact CIP requirements are not adequate protections for some entities.</p>	
Likes 0	
Dislikes 0	

Response

The SDT thanks you for your comment. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Please see response to APPA comment.

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer

No

Document Name

Comment

Based on the lack of clarity that exists regarding whether criterion 2.12 would be applicable to all Control Centers, not just TO Control Centers, Duke Energy does not support the proposed modifications. In the CIP V5 Issues for Standard Drafting Team Consideration document, the V5TAG group suggests the following:

“Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.”

The sentence above from the V5TAG document, specifically makes reference to a need to clarify requirements on TO Control Centers that perform functional obligations of a TOP. As we have stated previously, this proposed modification could be interpreted to include all Control Centers, not just TO Control Centers. Was it the drafting team’s intent to clear up the “functional obligations of a TOP” issue by inserting the phrase “that monitor and control BES Transmission Lines” into the criterion of 2.12? Perhaps a better understanding of what “performing the functional obligations of” would be beneficial, since it is commonly used throughout Attachment 1.

If it was the drafting team’s intent that this proposed modification to the criterion only refer to TO Control Centers, we recommend revising said criterion to explicitly reference TO Control Centers.

Likes	0
Dislikes	0
Response	
Proposed Criterion 2.12 is applicable to all BES Cyber Systems associated with Control Centers (regardless of functional registration), not included in High Impact Rating (H), that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the associated table.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA	
Answer	No
Document Name	
Comment	
Please see our comments for Question 1.	
Likes	0
Dislikes	0
Response	
Please see response to question 1.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

See our comments, rationale and alternate proposal as provided in our response to question 2.

Likes 0

Dislikes 0

Response

Please see response to question 2.

David Gordon - Massachusetts Municipal Wholesale Electric Company - 5

Answer

No

Document Name

Comment

MMWEC supports the comments submitted by APPA, and suggests adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."

Likes 0

Dislikes 0

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

Jack Cashin - American Public Power Association - 4

Answer

No

Document Name

Comment

Public power supports the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers. However, as proposed, Criterion 2.12 is ambiguous as to how the "aggregate weighted value" is derived. Is it derived by summing the values for all Transmission Lines monitored and controlled by a Control Center, or should it be derived by summing the value for Transmission Lines monitored and controlled by BES Cyber Systems located at the Control Center? Also, the criterion is not clear on whether "control" refers to control by personnel at the Control Center (e.g., by verbal instruction to field personnel) or to control by a BES Cyber System.

APPA suggests adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."

Public power appreciates the SDT efforts for clarifying the applicability requirements for a TO Control Center that performs the functional obligations of a TOP. We have some suggested language for Criterion 2.12 that we feel removes some ambiguity and possible interpretation questions. Our suggested language is as follows:

"Cyber Assets used to control BES Transmission lines, located at Control Centers or backup Control Centers, where the summed weighted value (according to the table below) of each BES Transmission Line controlled and monitored exceeds 6000."

Likes	5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
-------	---	--

Dislikes	0	
----------	---	--

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	No
--------	----

Document Name	
Comment	
Hydro One supports comments submitted by NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Please see response to NPCC RSC comment.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 5 response.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI comment.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	

See comments on question #1.	
Likes	0
Dislikes	0
Response	
Please see response to question 1.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	No
Document Name	
Comment	
<p>We support the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers. However, as proposed, Criterion 2.12 is ambiguous as to how the "aggregate weighted value" is derived. Is it derived by summing the values for all Transmission Lines monitored and controlled by a Control Center, or should it be derived by summing the value for Transmission Lines monitored and controlled by BES Cyber Systems located at the Control Center? Also, the criterion is not clear on whether "control" refers to control by personnel at the Control Center (e.g., by verbal instruction to field personnel) or to control by a BES Cyber System.</p> <p>We suggest adding the following sentence (similar to wording in criteria 2.1 and 2.1) to the end of the proposed Criterion 2.12. "The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below."</p>	
Likes	0
Dislikes	0
Response	

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the weighting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

See the response to question 2 above

Likes 0

Dislikes 0

Response

Please see response to question 2.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer No

Document Name

Comment

See comments on question #2.

Likes 0

Dislikes 0

Response

Please see response to question 2.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
Please see response to Robert Blackney comment on behalf of Southern California Edison.	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	No
Document Name	
Comment	
<p>NRG has a concern that there may be confusion on what the drafting team’s intent is in reference to proposed language pertaining to BES Cyber System’s span of control instead of the BES Cyber System monitors and controls. Industry interpretation of the current language leads NRG stakeholders to believe that the Rationale information may not match up correctly with the CIP-002-6 Standard. (NRG requests clarity on the operation authority versus capability). NRG requests that the drafting team provide clarity on what their intent is in reference to Criterion 2.12 and verify the alignment of the rationale document and the standard.</p> <p>Question: Does control include the ability to issue an operating instruction through another element besides a BES Cyber System element? Is it the intent of the SDT, that a TOP could drop from Medium to Low based on these calculations? It seems that most if not all TOPs are Medium and this can reduce them to Low which may be a concern for the industry.</p>	
Likes 0	
Dislikes 0	

Response

The SDT thanks you for your comment. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

Likes 0	
---------	--

Dislikes 0	
------------	--

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

Suggest 3000 points to be in-line with Criterion 2.5. Concerns that entities with large amounts of 100-199kV lines would be excluded (6000 points = 24 100kV lines).

Likes 0	
---------	--

Dislikes	0
Response	
<p>The SDT appreciates your comment and asserts that proposed Criterion 2.12 categorizes medium impact BES Cyber Systems, associated with Control Centers that monitor and control BES Transmission Lines, commensurate with their risk to the reliability of the BES. The SDT used Criterion 2.5 as a basis for developing proposed Criterion 2.12. In Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station/substation. The SDT doubled this value to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls BES Transmission Lines.</p>	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
NRECA supports the proposed modifications.	
Likes	0
Dislikes	0
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	

Comment

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

Please see response to Security Working Group comment.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer

Yes

Document Name

Comment

ERCOT ISO signs on to the SRC + SWG comments.

Likes 0

Dislikes 0

Response

Please see response to SRC + SWG comment.

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Yes

Document Name

Comment

SNPD only agrees with the weighted approach to identify ratings of Control Centers. A BES Cyber System that is an integrated part of a Control Center, and involves one or more BES Reliability Operating Service (BROS), should have a Medium Impact rating by association. The introduction of Span of Control, from the SDT is somewhat confusing language for SNPD.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. Please note that the language, “span of control” is not in the language of the Criterion, it is used to help explain the difference between the functional registration and the Transmission monitoring and control services the Control Center can perform.

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Document Name

Comment

MidAmerica would like to change its answer for this question to NO.

MidAmerican agrees with EEI's comments. Please see EEI's Comments below:

See our comments, rationale and alternate proposal as provided in our response to question 2.

Likes 0

Dislikes 0

Response

Please see response to question 2.

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Please see response to APPA comments.

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light

Answer

Document Name

Comment

Seattle City Light supports the comments of Cowlitz PUD and APPA.

Likes 0

Dislikes 0

Response

Please see response to Cowlitz PUD and APPA comments.

6. Implementation Plan: Do you agree with the SDT’s proposed Implementation Plan? If you agree with the proposed implementation time period, please note the actions you will take that require this amount of time to complete. If you think an alternate implementation time period is needed – shorter or longer - please propose an alternate implementation plan and provide a detailed explanation of actions and time needed to meet the implementation deadline.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes 0

Response

Please refer to the SDT’s response to Southern California Edison’s comment(s).

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

It is premature in our opinion to comment on the implementation plan because Ameren disagrees with the revisions.

Likes 0

Dislikes 0

Response	
The SDT thanks you for your comment. Please see the SDT’s response to EEI's comments on the proposed revisions.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 6 response	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment. Please see the SDT’s response to EEI's comments on the proposed revisions.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
It is premature to comment on the implementation plan because EEI disagrees with the proposed revisions to the standard.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment. Please see the SDT’s response to EEI's comments on the proposed revisions.	

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Based on the lack of clarity on the scope of criterion 2.12, we cannot agree that 12 months would be a sufficient time to address impact changes resulting from an unplanned change to the system.	
Likes 0	
Dislikes 0	
Response	
The SDT thanks you for your comment. The SDT has removed the Planned and Unplanned Changes sections of the Implementation plan and intends to address this matter more broadly across the entire body of CIP standards in the future.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Enforcement schedules triggered by a system change or periodic review should be incorporated directly within the Standard, not within a standalone Implementation Plan. An example of doing this is CIP-014-2 R5. The “unplanned changes compliance implementation table” in the Implementation Plan creates a situation where this Implementation Plan is never fully vested/implemented. An Implementation Plan should be used to dictate timelines required to implement a requirement, where timelines allowing for compliance maintenance (after Standard is fully implemented) should be incorporated directly within the standard, which allows the Implementation Plan itself to expire. This supports NERC’s implementation timeline reporting in Col L, here .	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

The SDT asserts that this concept does not deviate from the existing Implementation Plan. The SDT is simply carrying forward these concepts from the previously approved CIP-002-5.1 Implementation Plan.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

It is premature to comment on the implementation plan because MEC disagrees with the revisions.

Likes 0

Dislikes 0

Response

See the SDT's response to MEC's comments.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer No

Document Name

Comment

No Comment

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
<p>AZPS recommends that the proposed implementation time period be extended to 24 months for all options. Regardless of whether a facility’s categorization is revised from Low to Medium or Medium to High, the effort required would involve the design and implementation of new or different technology, new or revised processes, procurement and contracting efforts, etc. To design and implement an approach to compliance could – alone – take 12 months. When the additional time required for and uncertainty associated with the execution and completion of the supply chain and procurement processes are considered, implementation efforts could easily exceed 12 months. For this reason, implementation efforts should be allotted 24 months for completion as such timeline better aligns with the time needed for analysis, procurement of long lead items, and actual work.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT thanks you for your comment. The SDT has removed the Planned and Unplanned Changes sections of the Implementation plan and intends to address this matter more broadly across the entire body of CIP standards in the future.</p>	
Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
<p>NIPSCO is in support of the comment provided by EEI below.</p> <p>"It is premature to comment on the implementation plan because EEI disagrees with the revisions."</p>	
Likes	0

Dislikes	0
Response	
See the SDT's response to EEI's comments.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation recommends an initial implementation period of 18 months to allow entities time to determine the effects of the revised Impact Rating Criteria and an additional 18 months to comply.	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment. The SDT has removed the Planned and Unplanned Changes sections of the Implementation plan and intends to address this matter more broadly across the entire body of CIP standards in the future.	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	No
Document Name	
Comment	
N&ST agrees with the proposed implementation time frames in the draft Implementation Plan. However, N&ST believes there a number of issues with the accompanying narrative that should be addressed:	

- Third paragraph under heading, “Planned and Unplanned Changes:” N&ST does not believe it is possible for “unplanned” changes, defined in the Implementation Plan document as changes not planned and implemented by the responsible entity, to be made to one or more of that entity’s BES Cyber Systems.

- That same paragraph describes a “...scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1,...” N&ST believes this condition is logically impossible. An unplanned change, outside of the hypothetical transmission substation, could only result either in (a) an existing Cyber Asset, not previously identified as a BES Cyber Asset, becoming part of a new or existing BES Cyber System, or (b) a low impact BES Cyber System being recategorized as a medium impact BES Cyber System.

N&ST recommends the following changes to the Implementation Plan’s timeline table:

- For ease of reference, table entries should be numbered.

- The Implementation Plan should state explicitly that the table’s third and fourth entries (an existing BES Cyber System is recategorized from medium to high or from low to medium impact) applies to responsible entities that have previously identified at least one medium impact BES Cyber System.

- N&ST finds it difficult to envision a scenario wherein a new high or medium impact BES Cyber System must be implemented as the result of an unplanned change (first and second entries in table). At the same time, N&ST believes it is possible, if unlikely, that an existing Cyber Asset could be recategorized as a BES Cyber Asset as the result of an unplanned change. If this is the scenario the Drafting Team had in mind, these timeline table entries should be clarified. Otherwise, N&ST recommends they be deleted.

Likes 0

Dislikes 0

Response

The SDT asserts that while unplanned changes resulting in newly identified BES Cyber System(s) or changes to categorization are unlikely, the SDT recognizes that they are possible. Should this occur, the Implementation Plan provides timelines for the effective dates of the requirements. That said, the SDT has removed the Planned and Unplanned Changes sections of the Implementation plan and intends to address this matter more broadly across the entire body of CIP standards in the future.

Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name	
Southern Company	
Answer	No
Document Name	
Comment	
<p>The question asks, “please note the actions you will take that require this amount of time to complete”, although there is no time afforded entities to complete any actions. The proposed Implementation Plan states “Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.” This does not allow entities adequate time to achieve compliance with ‘main R’ requirements to have ‘one or more documented processes’ at the time of approval. Updates to entity policies, programs, plans, and procedures would be required, regardless of whether or not the modifications result in the identification of new, or reclassification of existing BES Cyber Systems at Control Centers.</p> <p>The Implementation Plan does explicitly state “For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.” However, there is no explicit clarification whether the changes to CIP-002-6 are considered a <i>Planned</i> change, or an <i>Unplanned</i> change. This impacts entities where there is no change to BES Cyber System categorization, but yet policies, programs, plans, and procedures must comply as of the effective date of the new approved standard. For the 24 month implementation clause above, this needs to also explicitly state “This includes changes or updates necessary to entity policies, programs, plans or procedures to address these modifications in CIP-002-6.”</p>	
Likes	0
Dislikes	0
Response	
Thank you for your comment. The SDT asserts that the language in the Planned and Unplanned Changes section is sufficiently clear and does not plan to include specific language regarding updates necessary to entity policies, programs, plans or procedures.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	

Answer	No
Document Name	
Comment	
The implementation time period needed would be contingent on the status of the changes to the definition of Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is proposing a new Control Center definition to address the communication networks directive as it relates to CIP-012.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
The following language is not adequately clear.	
“Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)” (24 months)	
This language needs to be clarified to clearly identify that 12 months is for the first medium or high impact BES Cyber System for this asset.	
Likes 0	
Dislikes 0	
Response	

The SDT asserts that the Implementation Plan is clear in this area and does not deviate from the existing Implementation Plan. The SDT is simply carrying forward these concepts from the previously approved CIP-002-5.1 Implementation Plan.

Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer Yes

Document Name

Comment

SNPD does not have comments on Question 6.

Likes 0

Dislikes 0

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer Yes

Document Name	
Comment	
<p>AECI requests the SDT to revise the implementation plan to provide added clarity. AECI suggests moving the statement, “For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.” to the beginning of the Planned/Unplanned Changes section of the Implementation Plan. It is confusing to read through all of the planned/unplanned options in the associated table and finally conclude with the statement that is most impactful to Responsible Entities.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT has deleted the Planned and Unplanned Changes section of the Implementation Plan.</p>	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
<p>ERCOT ISO signs on to the SRC + SWG comments.</p>	
Likes	0
Dislikes	0
Response	
<p>Jack Cashin - American Public Power Association - 4</p>	

Answer	Yes
Document Name	
Comment	
We agree with the intent of the implementation plan but feel that the unintended consequences of potential interpretations could bring assets into scope, thereby requiring recalibration of compliance programs in an ongoing manner.	
Likes 5	Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
The SDT has clarified the Planned and Unplanned Changes section by removing it from the Implementation Plan to the Standard.	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Salt River Project supports comments submitted by APPA.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes

Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
NRECA supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	

Consider further clarification of the classification of planned or unplanned changes. Existing definitions are vague with regard to regard to change of facility ownership, criterion that are based on agreements (2.7 NUC-001) or other entities or internal.

Likes 0

Dislikes 0

Response

The SDT is considering moving forward with language with the classification of planned or unplanned changes in the standard.

Russell Noble - Cowlitz County PUD - 3

Answer Yes

Document Name

Comment

Cowlitz PUD supports APPA comment.

Likes 1

Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities

Answer Yes

Document Name

Comment

Colorado Springs Utilities supports Cowlitz PUD and APPA comments

Likes	0
Dislikes	0
Response	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Lotz - City of Independence, Power and Light Department - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	
Likes 0	

Dislikes	0
Response	
<p>Rachel Coyne - Texas Reliability Entity, Inc. - 10</p>	
Answer	
Document Name	
Comment	
<p>While Texas RE does not necessarily object to the proposed Implementation Plan timeframes, the IP, as currently drafted, could introduce ambiguity regarding the expected compliance timelines for entities with Control Centers that are would be newly subject to the proposed CIP-002-6 Criteria 2.12 definition. In particular, Texas RE requests the SDT should clarify whether the change to the Control Center criteria would constitute a planned or unplanned change.</p> <p>The standard will become effective immediately upon the effective date of the FERC order approving the revisions. However, the new criteria presumably will interact with the impact rating review criteria set forth in CIP-002-5.1 R2. Specifically, Transmission Owners with Control Centers that satisfy the proposed 2.12 criteria presumably will have to identify those Control Centers during its periodic 15-month review of its Medium Impact BES Cyber System identifications. As such, depending on the time of the approval, entities could have as much as 15 months to properly categorize and implement medium impact controls for any Control Centers now captured by the changes to the CIP-002-5.1 Criteria 2.12 language. Further, entities may possibly have an additional 12 months beyond the 15 month categorization window if the SDT changes fall within the definition of an “unplanned change.” That is, “any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity.” Texas RE recommends that the SDT clarify this timeline, and, particularly, whether the SDT intends for the additional 12-month period for unplanned changes to be applicable in these circumstances.</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT moved the Planned and Unplanned section to the standard.</p>	

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Document Name	
Comment	
<p>MidAmerica would like to change its answer for this question to NO.</p> <p>MidAmerican agrees with EEI's comments. Please see EEI's Comments below:</p> <p>It is premature to comment on the implementation plan because EEI disagrees with the revisions.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT thanks you for your comment. Please see the SDT's response to EEI's comments on the proposed revisions.</p>	
Jeanne Kurzynowski - Consumers Energy Company - 1 - RF	
Answer	
Document Name	
Comment	
<p>No comment.</p>	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	

Comment

As the IESO does not own or operate BES Transmission Lines we have no opinion or comment on the implimentation plan.

Likes 0

Dislikes 0

Response

7. The SDT considered a number of approaches and determined that proposed CIP-002-6 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for a more cost effective approach that addresses the reliability objective, please provide your recommendation and, if appropriate, technical justification.

Jeanne Kurzynowski - Consumers Energy Company - 1 - RF

Answer

No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. In the case where an entity determines that a Control Center already meets High Impact criteria, there is no need for further evaluation to determine if a lower, and thus irrelevant criteria, is also applicable. Once a Control Center is deemed to meet the High Impact criteria, the evaluation of that Control Center is complete.

Wendy Center - U.S. Bureau of Reclamation - 5**Answer**

No

Document Name**Comment**

Reclamation recommends that the Impact Rating Criteria in CIP-002 Attachment 1 be simplified, using the methodology described in the response to Question 1, to reduce the overall impact of CIP-002-6 and allow entities to reduce the time spent “review[ing] the identifications in Requirement R1 and its parts (and update[ing] them if there are changes identified) at least once every 15 calendar months” and the cost of implementing the standard.

Likes 0

Dislikes 0

Response

The SDT appreciates your comments. The SDT is only authorized to address the TOCC issues as identified in the Standards Authorization Request for Project 2016-02. The SDT has revised criteria 2.12 to address the risk to the BES presented by the BES Cyber Systems that are capable of operating transmission.

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1**Answer**

No

Document Name**Comment**

NIPSCO is in support of the comment provided by EEI below.

"It is premature to comment on the cost effectiveness of the proposed changes because EEI disagrees with the revisions."

Likes 0

Dislikes 0

Response

See the SDT's response to EEI's comments.

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. In the case where an entity determines that a Control Center already meets High Impact criteria, there is no need for further evaluation to determine if a lower, and thus irrelevant criteria, is also applicable. Once a Control Center is deemed to meet the High Impact criteria, the evaluation of that Control Center is complete.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. In the case where an entity determines that a Control Center already meets High Impact criteria, there is no need for further evaluation to determine if a lower, and thus irrelevant criteria, is also applicable. Once a Control Center is deemed to meet the High Impact criteria, the evaluation of that Control Center is complete.

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

Removal of the guidelines and technical basis on which entities implemented their CIP-002 BES Cyber System identifications and classifications could cause significant re-work if it results in compliance interpretations other than what the SDT intended. Re-work is not cost effective.

Likes 0

Dislikes 0

Response

There is no plan to remove the GTB from the standard at this time.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
It is premature to comment on the cost effectiveness of the proposed changes because MEC disagrees with the revisions.	
Likes	0
Dislikes	0
Response	
See the SDT's response to MEC's comments.	
Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
See our response to question 6. Without clarity on the scope, it is difficult to determine the cost effectiveness.	
Likes	0
Dislikes	0
Response	
See response to comments in question 6.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	
Comment	
It is premature to comment on the cost effectiveness of the proposed changes because EEI disagrees with the revisions.	
Likes 0	
Dislikes 0	
Response	
See response to EEI's comments.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
KCP&L incorporates by reference Edison Electric Institute's (EEI) Question 7 response.	
Likes 0	
Dislikes 0	
Response	
See response to EEI's comments.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

See the response to question 6 above.

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 5, 3, 1; - Jeff Johnson

Answer

No

Document Name

Comment

Item 7 is ambiguous and needs to be explained. SDG&E seeks clarification to what the “cost effective manner” element is of this proposed change to CIP-002-5.1.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

No

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes	0
Dislikes	0
Response	
Please see response to comments submitted by Robert Blackney on behalf of Southern California Edison	
Regan Haines - TECO - Tampa Electric Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities supports Cowlitz PUD and APPA comments	
Likes	0
Dislikes	0
Response	
Please see response to Cowlitz PUD and APPA comments.	

Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
<p>AZPS agrees that the SDT’s proposal meets the reliability objectives in a cost effective manner so long as a reasonable implementation period, i.e., at least 24 months, is allotted. Otherwise, entities to which these modifications are applicable may expend significant resources unnecessarily to meet timeframes that were, at their time of proposal, unreasonable. Such unnecessary expenditures would gravely adversely impact the cost-effectiveness of the proposed revisions.</p>	
Likes	0
Dislikes	0
Response	
The SDT thanks you for your comment.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Cowlitz PUD supports APPA comment.	
Likes	1
Dislikes	0
Response	
Please see response to APPA’s comments.	
Richard Vine - California ISO - 2	

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the Security Working Group (SWG)	
Likes 0	
Dislikes 0	
Response	
Please see response to SWG comments.	
Lona Calderon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Salt River Project supports comments submitted by APPA.	
Likes 0	
Dislikes 0	
Response	
Please see response to APPA comments.	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	

MMWEC supports the concept of establishing criteria for Medium Impact Control Centers and Low Impact Control Centers. We support the approach of basing the criteria on "aggregate weighted value" of Transmission Lines controlled by BES Cyber Systems located at the Control Centers.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comments.

Jack Cashin - American Public Power Association - 4

Answer

Yes

Document Name

Comment

Based on the perception of the SDT intent, public power agrees with the weighted values for transmission lines that the BES cyber system monitors and controls approach and that the allowing for low impact Control Centers is a positive action.

The changes proposed should reduce cost and/or potentially provide flexibility in compliance options.

Likes 5

Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

The SDT thanks you for your comment.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer

Yes

Document Name	
Comment	
ERCOT ISO signs on to the SRC + SWG comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to the SRC + SWG comments.	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have comments on Question 7.	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Cain - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,MRO,WECC,Texas RE,SERC,SPP RE, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Francis - SRC - 2,3 - MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF, Group Name SRC + SWG	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes	0	
Response		
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro		
Answer	Yes	
Document Name		
Comment		
Likes	1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes	0	
Response		
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation		
Answer	Yes	
Document Name		
Comment		
Likes	0	
Dislikes	0	
Response		
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1		
Answer	Yes	

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Lotz - City of Independence, Power and Light Department - 3,5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
As the IESO does not own or operate BES Transmission Lines we have no opinion or comment on the implementation plan.	
Likes	0
Dislikes	0
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	
Comment	

The SDT should strongly consider replacing CIP-002 and the associated CIP standards with an alternative non-prescriptive approach that focuses on effective cyber and physical security and adapt the enforcement approach to be consistent with those used in financial auditing. This alternative approach would reduce costs and allow Registered Entities to focus on maintaining a secure power grid .

Likes 0

Dislikes 0

Response

The SDT appreciates your comments. The SDT is only authorized to address the TOCC issues as identified in the Standards Authorization Request for Project 2016-02. The SDT has revised criteria 2.12 to address the risk to the BES presented by the BES Cyber Systems that are capable of operating transmission.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer

Document Name

Comment

We have not performed a cost analysis on the proposed changes.

Likes 0

Dislikes 0

Response

Mary Ann Todd - Illinois Municipal Electric Agency - 4

Answer

Document Name

Comment

IMEA supports APPA comments.	
Likes	0
Dislikes	0
Response	
Please see response to APPA comments.	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No Response.	
Likes	0
Dislikes	0
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes	0

Dislikes	0
Response	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	
Likes	0
Dislikes	0
Response	
Please see response to Cowlitz PUD and APPA comments.	

8. If you have additional comments on proposed CIP-002-6, Attachment 1, Criterion 2.12 that you have not provided in response to the questions above, please provide them here.	
Kara White - NRG - NRG Energy, Inc. - 3,4,5,6 - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF	
Answer	
Document Name	
Comment	
N/A	
Likes	0

Dislikes	0
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
<p>SCE does not agree with the first paragraph that has been inserted into the Guidelines and Technical Basis (GTB) section of the proposed standard.</p> <p>SCE used the existing Guidelines and Technical basis section of CIP-002 (and other CIP standards) to inform the implementation of NERC compliant CIP programs and, consequently, SCE does not think that NERC should remove this section from the proposed standard without providing a replacement process to inform the understanding of the impact rating criteria in CIP-002, and the impact of BES Cyber System impact ratings on the applicability of other CIP standards.</p> <p>In proposed standard CIP-002-6, NERC states that the guidance that is normally provided in the GTB section of the standard could be moved into the accompanying Implementation Guidance document, however, NERC does not provide any assurance that the Implementation Guidance will be released in a timely manner, or if industry participants would have the opportunity to vet and/or approve the information. Consequently, SCE does not agree with NERC’s proposal to remove the GTB sections of CIP-002-6 unless NERC can provide clear and discrete next steps about what implementation information will be made available to industry participants, when NERC will release the information, and NERC provides assurance that industry stakeholders will have an opportunity to reviewing/vet the information prior to its implementation.</p> <p>Furthermore, SCE does not believe that the Implementation Guidance document is an appropriate place to present the information that would typically be accessible in the GTB section of the standard. Currently, the GTB section of the standards provides valuable examples that clarify the specific compliance circumstances and variables NERC could/would review during the NERC audit process. Additionally, the GTB provides industry stakeholders insight to the SDT’s drafting process and the underlying intents of the proposed requirements in a draft standard. Conversely, Implementation Guidance documents provide a specific, NERC endorsed approach that an entity can use to achieve compliance with a particular requirement. Therefore, SCE does not think it would be appropriate to relocate information from</p>	

the GTB section into Implementation Guidance. If necessary, the SDT could modify Attachment 1 of the proposed standard to include the guidance from the GTB.

Having said that, if NERC disagrees with SCE and believes that Implementation Guidance is an appropriate place to present the guidance normally found in the GTB section, SCE recommends that NERC issue the Implementation Guidance document for the review and approved of industry participants. Specifically, SCE believes that the Implementation Guidance document should pass through an industry participant ballot process before to the final ballot for CIP-002 (analogous to NERC’s process for CIP-013).

Lastly, SCE is concerned that removal of the GTB may impact SCE’s ability to support the approval of the proposed CIP-002-6. SCE recommends NERC address the concerns surrounding GTB before taking CIP-002-6 to a second ballot.

Likes 0

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer

Document Name

Comment

Are there any RC and TOP functional obligations that SNPD should consider, other than the services already stated in BROS?

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. The SDT has revised criterion 2.12 to address the confusion related to the term “functional obligation,” as noted in the VTAG transfer document. To address the risk to the BES presented by the BES Cyber Systems that are capable

of operating transmission, the revision is intended to address entities that perform tasks of operating transmission, regardless of registration. Research performed by the SDT did not show the same concern with the other Criteria.

Michael Johnson - Burns & McDonnell - NA - Not Applicable - FRCC,MRO,WECC,Texas RE,NPCC,SERC,SPP RE,RF

Answer

Document Name

Visio-CIP V6 Diagram Trans - 20170826 - 2-12.pdf

Comment

As part of the diagrams provided for 2.12, we are providing a suggested additional diagram we feel the Standard should display in the Supplemental Material section. Even though the text for 2.12 indicates it is for “BES Transmission Lines”, it is not clear that generator lead line(s) should not be counted as part of aggregated weight value of 6000. To avoid having to have separate guidance document like Criteria 2.5 has (CIP-002-5, Requirement R1, Attachment 1: Criterion 2.5 and Generator Interconnection), we recommend the standard include a third diagram which clearly indicates the generator lead line(s) are not part of the aggregated weighted value. A suggested diagram has been provided to Wendy Muller since diagrams may not import correctly to the comment portal. The file name of the diagram provided to Wendy was “Visio-CIP V6 Diagram Trans - 20170826 - 2-12.pdf”

Likes 0

Dislikes 0

Response

Diagram included below

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

Document Name

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison

Likes 0

Dislikes	0
Response	
Please see response to SCE's comments.	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	
<p>While Vectren's subject matter experts are in agreement with the proposed modifications for CIP-002-06 Attachment 1 Criterion 2.12, Vectren does not agree with removing the Guidelines and Technical Basis (G&TB) from CIP-002-6. The G&TB addresses complex concepts and provides additional guidance regarding what should be considered when developing the methodology to categorize Facilities, systems, and equipment into high-, medium-, and low-impact ratings. It also provides clarification for some ambiguities in the requirements and has been referenced as one source in our documentation of how we arrived at our approach. It is unclear where this information will reside or how it will be maintained once it is removed from the CIP-002-6 standard. The removal of the G&TB should be delayed until a defined removal process has been developed by NERC staff, including the new location of the information.</p> <p>Vectren is committed to the safety and reliability of the BES and committed to compliance excellence. We appreciate the efforts of the Standard Drafting Team and will be glad to provide any additional detail upon request. Thank you for allowing Vectren the opportunity to provide comments on this draft standard.</p>	
Likes	0
Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
David Jendras - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	
We support comments offered by EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI's comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	
Document Name	
Comment	
<p>Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document.</p> <p>NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.</p> <p>The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, we do not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.</p>	
Likes 0	

Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light	
Answer	
Document Name	
Comment	
Seattle City Light supports the comments of Cowlitz PUD and APPA.	
Likes	0
Dislikes	0
Response	
See response to APPA.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has the following comments regarding the Guidelines and Technical Basis:	
<ul style="list-style-type: none"> Texas RE requests clarification as to what Part 1, which is mentioned several times, in the Guidelines and Technical Basis refers. 	

- It appears version 5 is left out of the sentence on page 20: “This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment”.
- Page 27 of the GTb contains a reference to functional obligations. Since the intent of this project was to clarify the use of the term “to perform the functional obligations of” and the SDT created the 2.12 criteria in Attachment 1, it does not seem necessary to use this term in the GTB. Texas RE requests the SDT ensure that it makes sense to use the term in this case.
- Page 33 contains the phrase “Associated data centers”. As it is important and to be consistent, Texas RE recommends the phrase be included in criteria 2.12 of Attachment 1.
- Page 37 describes the SDT’s rationale behind some of the CIP version 5 changes. It would be helpful to have this description for the CIP-002-6 changes.

Texas RE noticed the Violation Severity Level table references CIP-002-5.1a.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. The SDT has made modifications to remove some references to transitioning from prior versions as the industry has already transitioned to the CIP version 5 standards. The SDT has adjusted the GTB associated with criterion 2.12, but references to the phrase “perform the functional obligation” remain in the CIP-002 standard. Research performed by the SDT did not show the same concern with the other Criteria. The SDT did not include associated data centers in criterion 2.12 as they are already included as part of the Control Center definition. The SDT has included rationale for Criterion 2.12 and attempted to make conforming changes to the standard as appropriate.

Don Schmit - Nebraska Public Power District - 5

Answer

Document Name

Comment

None.	
Likes	0
Dislikes	0
Response	
<p>Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb</p>	
Answer	
Document Name	
Comment	
KCP&L incorporates by reference Edison Electric Institute’s (EEI) Question 8 response.	
Likes	0
Dislikes	0
Response	
Please see response to EEI’s comments.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
PacifiCorp supports EEI comments.	

Likes	0
Dislikes	0
Response	
Please see response to EEI's comments.	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	
Document Name	
Comment	
<p>While Vectren's subject matter experts are in agreement with the proposed modifications for CIP-002-06 Attachment 1 Criterion 2.12, Vectren does not agree with removing the Guidelines and Technical Basis (G&TB) from CIP-002-6. The G&TB addresses complex concepts and provides additional guidance regarding what should be considered when developing the methodology to categorize Facilities, systems, and equipment into high-, medium-, and low-impact ratings. It also provides clarification for some ambiguities in the requirements and has been referenced as one source in our documentation of how we arrived at our approach. It is unclear where this information will reside or how it will be maintained once it is removed from the CIP-002-6 standard. The removal of the G&TB should be delayed until a defined removal process has been developed by NERC staff, including the new location of the information.</p> <p>Vectren is committed to the safety and reliability of the BES and committed to compliance excellence. We appreciate the efforts of the Standard Drafting Team and will be glad to provide any additional detail upon request. Thank you for allowing Vectren the opportunity to provide comments on this draft standard.</p>	
Likes	0
Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document	
Likes 0	
Dislikes 0	
Response	
Sheranee Nedd - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	
Document Name	
Comment	
PSEG generally supports EEI's comments on Questions 8. PSEG does not agree with NERC's approach to remove the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale.	
Likes 4	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph; PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	
Response	

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Jack Cashin - American Public Power Association - 4

Answer

Document Name

Comment

The possible new interpretations could impact the application of other criteria. (2.11 and 2.13)

The removal of the Guidelines and Technical Basis (GTB) section from the standard reduces the standard’s continuity and authority. This removal makes it so that the language in the requirements includes the details currently included in guidance. Such inclusion makes requirements out of guidance.

Likes 5

Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 3, Oens Mark; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam; Snohomish County PUD No. 1, 6, Lu Franklin; Public Utility District No. 1 of Snohomish County, 1, Duong Long

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

NERC’s statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language

currently contained solely in the requirements of the standard while removing the original SDT intent by which was the basis for industry approval and implementation.

The problem is that registered entities’ existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC’s approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended “to support the implementation of the associated Reliability Standard.” Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT’s intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC and Regional auditors in understanding the SDT’s intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

EEI is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot.

Likes 1	PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer

Document Name

Comment

Duke Energy has some concerns regarding the removal of the Guidelines and Technical Basis Section (GT&B) of the standard. While the GT&B section is not considered to be an enforceable part of the standard (as opposed to requirements), it may be used by some entities to get a better understanding of the standard’s expectations, as well as determining a compliance approach. If the GT&B section is removed from the standard, we recommend that it be incorporated into ERO Enterprise-Endorsed Implementation Guidance.

Likes 0

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Russel Mountjoy - Midwest Reliability Organization - 10

Answer

Document Name

Comment

Provide clarity: If each end of a line is controlled and monitored by separate Control Centers (same or different entities) is the line weight counted for each Control Center?

Likes 0

Dislikes 0

Response

The SDT notes that each Responsible Entity is responsible for protecting the BES Cyber Systems needed to fulfill their functional requirements to maintain BES reliability. As stated in the requirement, the weighting is determined by summing the Transmission lines that the Control Center in question monitors and controls.

Lona Calderon - Salt River Project - 1,3,5,6 - WECC

Answer

Document Name

Comment

Salt River Project supports comments submitted by APPA.

Likes 0

Dislikes 0

Response

Please see response to APPA's comments.

Mike Lotz - City of Independence, Power and Light Department - 3,5

Answer

Document Name

Comment

Other factors besides transmission values, such as customers served, should be used to determine an entities' impact. It should not be assumed that all entities will voluntarily implement and maintain security controls above the low impact threshold if not mandated to do so. The low impact requirements may not be adequate in all situations.

Likes 0

Dislikes 0

Response

The SDT thanks you for your comment. In drafting and approving the CIP v5 Standards, the Commission, ERO, and Industry collectively saw the need for, and benefit in, defining impact ratings as well as the requirements that would be applicable to each. The SDT sought to clarify Criteria 2.12 to help ensure that the standards do not mandate protection above the commensurate risk a given Control Center poses to the BES. The SDT asserts that the new Criteria 2.12 establishes a bright line that maintains adequate protection for BES Cyber Systems and does not introduce increased security risk, while providing practicality for Control Centers containing Low Impact BES Cyber Systems that monitor and control BES Transmission lines.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer

Document Name

Comment

IID fully supports SDT efforts so far, and regrets the need for submitting a negative ballot. However, the application interpretations received from regional auditors of the proposed criterion is cause for serious concern, and can impact application of other criteria in similar fashion.

Likes 0

Dislikes 0

Response

Thank you for your comments.

Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer

Document Name

Comment

LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company (LKE) submits these comments for NERC’s consideration. LKE strongly supports the comments submitted by Edison Electric Institute (EEI) with respect to the Guidelines and Technical Basis (GTB) portion of the draft changes to the standard. Specifically, LKE is deeply concerned with the proposed approach of removing the GTB section of the standards without the simultaneous posting of **1)** Technical Rationale prepared by the Standards Drafting Team for industry comment or **2)** potential Implementation Guidance developed through the Compliance Guidance policy. It is our understanding that the Standards Committee is working with NERC staff to develop a process for removal of the GTB sections from standards. We recommend that GTB sections not be removed from any standard until that process has been defined. As detailed in section 2.5 of the Standards Processes Manual (Rules of Procedures Appendix 3A), Application Guidelines are included, among other reasons, “to support the implementation of the associated Reliability Standard,” “establish relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” In many cases, and specifically in the case of CIP-002-5.1a, the GTB plays a critical role in determining the scope of the standard to which it applies. Consequently, removal of GTB sections without simultaneously publishing a Technical Rationale document as proposed for this standard creates unnecessary and significant ambiguity. Furthermore, removing the GTB may inadvertently contradict the Standards Process Manual and we suggest NERC should avoid any such appearance.

Likes	0
-------	---

Dislikes	0
----------	---

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
--------	--

Document Name	
---------------	--

Comment

Guidelines and Technical Basis

At NERC’s direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

The NSRF has concerns with removing the Guideline and Technical Basis from all Standard(s). Currently Entities feel they vote for the “entire standard” including the Guideline and Technical Basis. The NSRF understands that Entities are actually voting for the Requirements but the perception is that FERC approves all th verbiage and sections to the Entire Standard.

Likes 0

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees with Edison Electric Institute’s comments regarding the removal of the Guidelines and Technical Basis (GTB) from the Reliability Standard prior to final ballot. CenterPoint Energy does not agree with NERC’s proposal to remove the GTB without providng guidance on how the information in the GTB will be retained. CenterPoint Energy believes the GTB in CIP-002 provides pertinent information that establishes guidance for identifying and categorizing the BES Cyber Systems that would be subject to CIP-002, which sets the foundation of applicability for the other CIP standards. CenterPoint Energy is concerned that the removal of the GTB will provide less guidance to entities regarding the technical basis for the requirements and the intent of the Standard Drafting Team, which has been relied upon by the industry and regulatory authorities.

Likes 0

Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	
Document Name	
Comment	
FirstEnergy supports the comments supplied by EEI regarding the removal of the Guidelines and Technical Basis Section from the CIP-002 Standard. This section provides valuable application guidance that the industry has relied on in implementing the CIP-002 Standard, and should remain part of the Standard.	
Likes	0
Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments of the Security Working Group (SWG)

Likes 0

Dislikes 0

Response

See response to SWG.

David Rivera - New York Power Authority - 3

Answer

Document Name

Comment

Since the Guidance & Technical Basis (GTB) will be removed, we need clarification on where this GTB goes. Some GTB information such as the BROS (BES Reliability Operating Services) should be included in an Implementation Guideline and not a technical reference document.

Likes 0

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

Document Name

Comment

NERC’s statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

The problem is that registered entities’ existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC’s approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended “to support the implementation of the associated Reliability Standard.” Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT’s intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT’s intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

MEC is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot.

Likes	0
Dislikes	0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Tyson Archie - Platte River Power Authority - 5

Answer

Document Name

Comment

Platte River Power Authority (PRPA) supports the comments provided by the American Public Power Administration (APPA).

Likes 0

Dislikes 0

Response

See response to APPA.

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer

Document Name

Comment

NRECA appreciates the hard work of the drafting team over a long period of time on complex issues.

Likes 0

Dislikes 0

Response

Thank you for your comment.

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	
Document Name	
Comment	
<p>NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.</p> <p>The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, Con Edison does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.</p>	
Likes 0	
Dislikes 0	
Response	
<p>The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.</p>	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
<p>Cowlitz PUD supports APPA comment.</p>	
Likes 0	

Dislikes 0	
Response	
Please see response to APPA.	
Mary Ann Todd - Illinois Municipal Electric Agency - 4	
Answer	
Document Name	
Comment	
IMEA supports APPA comments.	
Likes 0	
Dislikes 0	
Response	
See response to APPA.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	
MEC supports the comments of EEI on this question. The content of the guidelines and technical basis is essential to convey the SDT’s intent, which was the basis for industry approval and implementation and therefore must continue to be a part of the standard. Also, the proposal to remove the guidelines and technical basis from CIP-002 is out of scope of the Standards Authorization Request, which states, “Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary.” This indicates continuation of the guidelines and technical basis, not removal.	

MEC also agrees with EEI's comments for questions #8	
Likes	0
Dislikes	0
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	
Document Name	
Comment	
Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).	
Likes	0
Dislikes	0
Response	
The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	
Document Name	

Comment

Utility Services supports the efforts of the Standard Development Team to date and believe that the revised language for Criteria 2.12 is a significant incremental step forward which will focus efforts on the most critical locations. We are aware of issues with the interpretation of the of the TOCC proposed version of Criteria 2.12 and encourage the Standard Development Team to clarify the specific language of criteria 2.12 to clarify the scoring application of Criteria 2.12. To that end, Utility Services supports the comments of the NPCC Regional Standards Committee suggesting revision of the criteria for clarity.

Likes 0

Dislikes 0

Response

The SDT asserts that the proposed requirement is clear in that the BES Cyber Systems are to be classified as Medium if they are associated with Control Centers that monitor and control BES Transmission lines that meet the wieghting criteria of 2.12. The Transmission lines to be summed are those that are identified as being part of the Bulk Electric System, which are in turn supported by BES Cyber Systems.

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

Document Name

Comment

Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).

Likes 0

Dislikes 0

Response

The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1

Answer

Document Name

Comment

NIPSCO is in support of the comment provided by EEI below.

"

NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.

The problem is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. As a result, EEI does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated. Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended "to support the implementation of the associated Reliability Standard." Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT's intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation

Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT’s intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

EEL is concerned that removal of the GTB may impact the ability for this standard to pass ballot. We recommend that NERC address these concerns before taking CIP-002-6 to a second ballot."

Likes 1	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla
Dislikes 0	
Response	
See the SDT’s response to EEL’s comments.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1 - RF	

Answer	
Document Name	
Comment	
<p>Additional savings for entities could be gained by not requiring evaluation of lower priority CIP-002-6, Attachment 1 Criteria, where applicable assets are determined to meet higher priority IRC Criteria (and are High Watermarked for the higher priority IRC Criteria/CIP Controls).</p>	
Likes	0
Dislikes	0
Response	
<p>The SDT asserts that if the BES Cyber Systems associated with a Control Center already meet the High Impact criteria, there is no need for a Responsible Entity to attempt to apply Criteria 2.12 to its environment. Criteria 2.12 states, "Control Centers, or backup Control Centers, not included in the High Impact Rating (H) above..." This statement relieves an entity of attempting to apply Criteria 2.12 to its Control Centers if the BES Cyber Systems associated with the Controls Centers were already acknowledged to be High Impact.</p>	
<p>Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion</p>	
Answer	
Document Name	
Comment	
<p>NERC's statement inserted into the first paragraph of the Guidelines and Technical Basis (GTB) regarding removal of the GTB before final ballot is a critical issue for this ballot. This creates an untenable situation where the approval of this standard must rest on the language currently contained solely in the requirements of the standard.</p> <p>Of significant concern is that registered entities' existing CIP programs have been built using the GTB as a guide to understanding the meaning of the impact rating criteria in CIP-002, which is used to identify the BES Cyber System impact ratings that set the foundation of applicability for the other CIP standards. Dominion Energy does not agree with NERC's approach to removing the GTB without providing transparent next steps as to which information will be retained in the Technical Rationale and how that rationale will be treated.</p>	

Implementation Guidance is also mentioned as a possibility for the SDT, but no certainty as to whether or when the SDT will develop it is provided. Alternatively, the SDT could modify the Attachment 1 criteria to include the guidance from the GTB.

It is also unclear why NERC is directing the removal of the GTB when the currently approved Standards Process Manual clearly allows the development of Application Guidelines as a component of a Reliability Standard, noting that such documents are intended “to support the implementation of the associated Reliability Standard.” Implementation Guidance is meant to gain NERC endorsement of specific approaches to compliance with a particular requirement or part of a requirement. Much of the GTB is more like application guidance; it is not necessarily an approach to compliance, but supports implementation by providing the SDT’s intent behind the requirements, which includes examples to further clarify this intent. However, if NERC disagrees and views the GTB to primarily consist of Implementation Guidance, then the SDT should be directed to convert this information into Implementation Guidance and NERC should endorse it in a ballot before the final ballot like it did with CIP-013.

It is also important to note that most of the CIP-002 GTB (excluding the redlined text for CIP-002-6) has been submitted with previous versions of the standard and has been relied upon not only by industry, but also by FERC in understanding the SDT’s intent behind the requirements. At this point, it is unclear if the Technical Rationale will be submitted to FERC along with the revised standard and how much of the GTB will be converted into Technical Rationale.

Likes 1	Long Island Power Authority, 1, Ganley Robert
Dislikes 0	
Response	
The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.	
Shannon Fair - Colorado Springs Utilities - 6, Group Name Colorado Springs Utilities	
Answer	
Document Name	
Comment	
Colorado Springs Utilities supports Cowlitz PUD and APPA comments	

Likes 0	
Dislikes 0	
Response	
See response to APPA.	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	
Document Name	
Comment	
(No additional comments)	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	
Document Name	
Comment	
We suggest that rationale similar to Criterion 2.12 should also be referenced for 1.3.	
Likes 0	
Dislikes 0	
Response	

The SDT thanks you for your comment. The intent of the SDT was to address the ambiguity created by the phrase "performs the functional obligation" within Criteria 2.12, and not to assess similar phrases throughout the standards that were not identified by the commission or v5TAG group for consideration.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer

Document Name

Comment

1. As this team is planning to submit the Guidelines and Technical Basis as a separate document from the Standard itself, Seminole requests the drafting team to revise the language “adversely impact the reliable operation” and make it more clear. This phrase is very unclear. How is an adverse impact quantitatively measured?
2. The Interpretation listed in Section C on page 13 of the redline, is that part of the Reliability Standard, or more of an Associated Document?
3. Should the Guidelines and Technical Basis be listed under Associated Documents (Section F) on p. 13 of 43 of the redline?
4. In the Guidelines and Technical Basis, the SDT has differentiated between Control Centers and backup Control Centers. However, in portions of the redline changes (see page 34 for example), the SDT only references Control Centers. This is confusing as Seminole isn’t sure if the drafting team purposely means not to include backup Control Centers in these sections where they are not specifically identified. The team should only use one term or define backup Control Centers (make it a NERC defined term) and reference both throughout the document.

Likes 0

Dislikes 0

Response

The SDT has no plans to take any further action removing the GTB at this time, as NERC is currently working with the Standards Committee to create a process of reviewing standards with GTBs.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	
Document Name	
Comment	
SVP appreciates the effort by the SDT to look at and improve criterion 2.12	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	
Document Name	
Comment	

I am in agreement with the proposed changes.

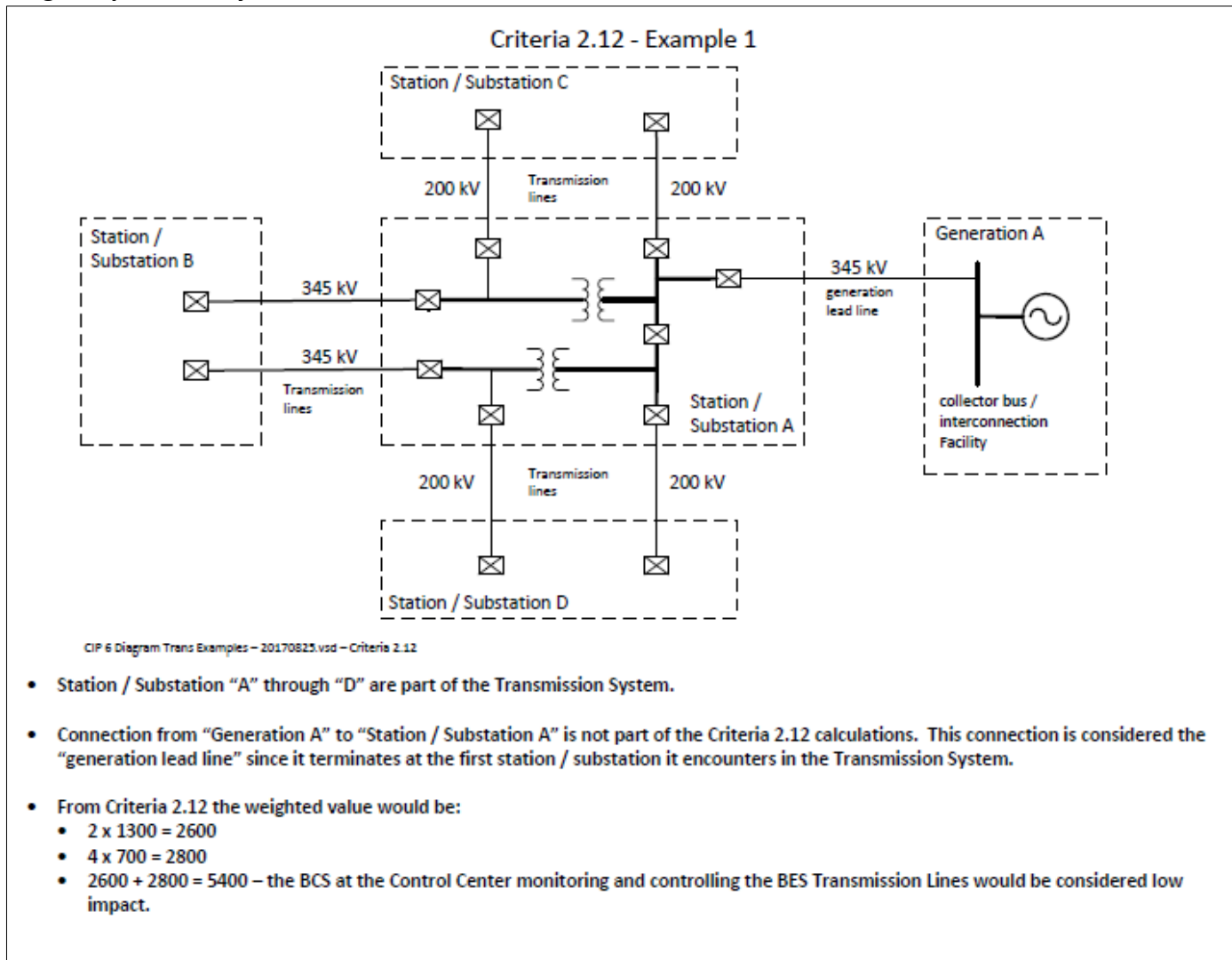
Likes 0

Dislikes 0

Response

Thank you for your comment.

Diagram provided by Michael Johnson Burns & McDonnell



End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018

Anticipated Actions	Date
45-day formal comment period with additional ballot	May 18 – July 2, 2018
10-day final ballot	July 30 – August 8, 2018
NERC Board	August 16, 2018

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See implementation plan for CIP-002-6.

- 6. Planned and Unplanned Changes:** If a Responsible Entity has a Planned Change¹ or Unplanned Change,² the Responsible Entity shall comply with the requirements in this Reliability Standard in accordance with the following:

For Planned Changes resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard upon the commissioned date of the Planned Change. For this provision, the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES. For requirements that contain periodic obligations, initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.

For Unplanned Changes, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below. As used in the table, the phrase “BES asset type” refers to the following BES asset types listed in Requirement R1 of CIP-002: (i) Control Centers or backup Control

¹ Planned Changes refer to changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity’s awareness. Planned Changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen by the Responsible Entity. Examples of Planned Changes include: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² Unplanned Changes refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity’s awareness or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of Unplanned Changes include: (1) when a Responsible Entity is notified (internally or externally) that a generation Facility has been designated as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year (CIP-002, Attachment 1, Criterion 2.3); (2) when a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified as critical to the derivation of an IROL and their associated contingencies (CIP-002, Attachment 1, Criterion 2.6); (3) when a generating resource that is connected at less than 100kV is designated as a new Blackstart Resource along with its Cranking Path (CIP-002, Attachment 1, Criterion 3.4); or (4) when a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in Criterion 2.10 of CIP-002, Attachment 1.

Centers; (ii) Transmission stations or substations; (iii) generation resources; (iv) systems and facilities critical to system restoration including Blackstart Resources and Cranking Paths and initial switching requirements; (v) Special Protection Systems that support the reliable operation of the Bulk Electric System; and (vi) the Distribution Provider Protection Systems specified in Applicability section 4.2.1.

Scenario of Unplanned Change	Implementation Period
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above, except that the Responsible Entity shall initially perform Part 2.2 of Requirement R2 by the date the Implementation Period ends where the Unplanned Change results in a high or medium impact BES Cyber System and the Responsible Entity previously had neither a high nor a medium impact BES Cyber System.

For Unplanned Changes resulting in a higher categorization for an existing BES Cyber System, the Responsible Entity shall continue to comply with the applicable requirements of the prior categorization during the Implementation Period defined above.

7. **Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

BES Cyber Systems The term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than “Real-time,” BES Cyber Assets are those Cyber Assets

that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.13 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

- 2.5.** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7.** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8.** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9.** Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry’s overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

- 2.12.** Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.13 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities.

However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of

BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is

necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.

- Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300

MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission

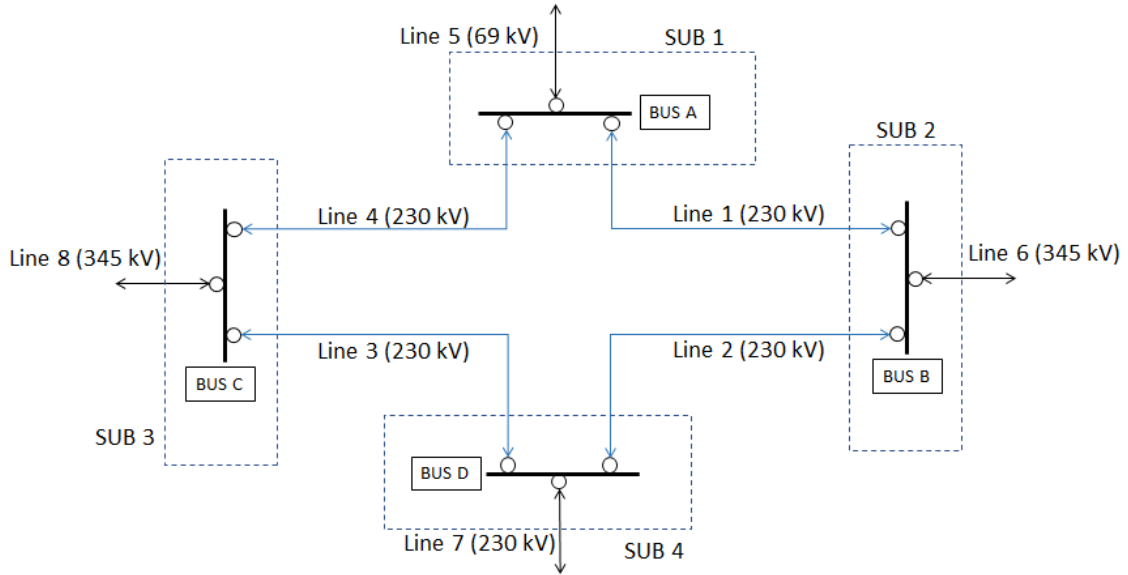
Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

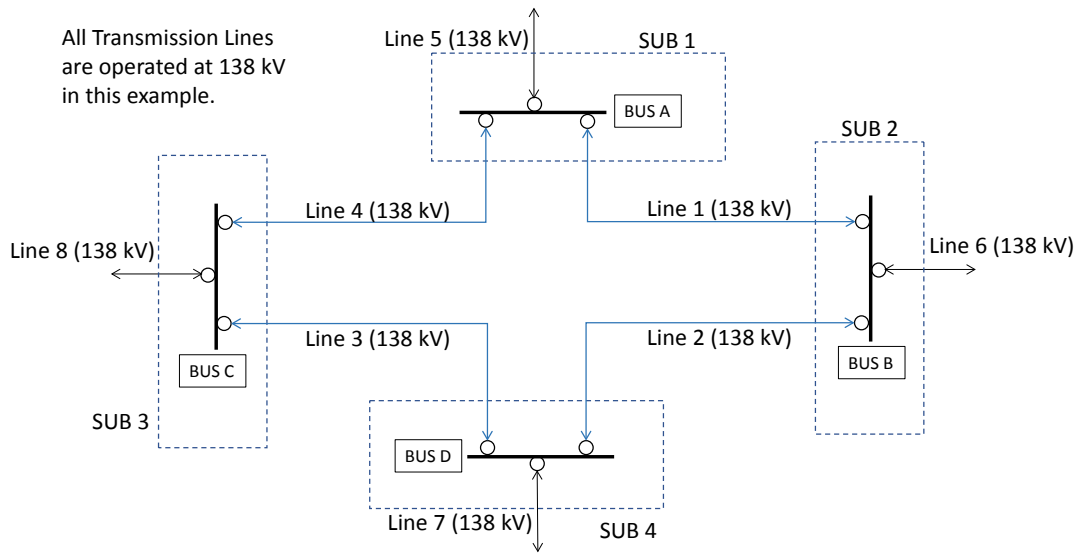
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A

100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration

assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

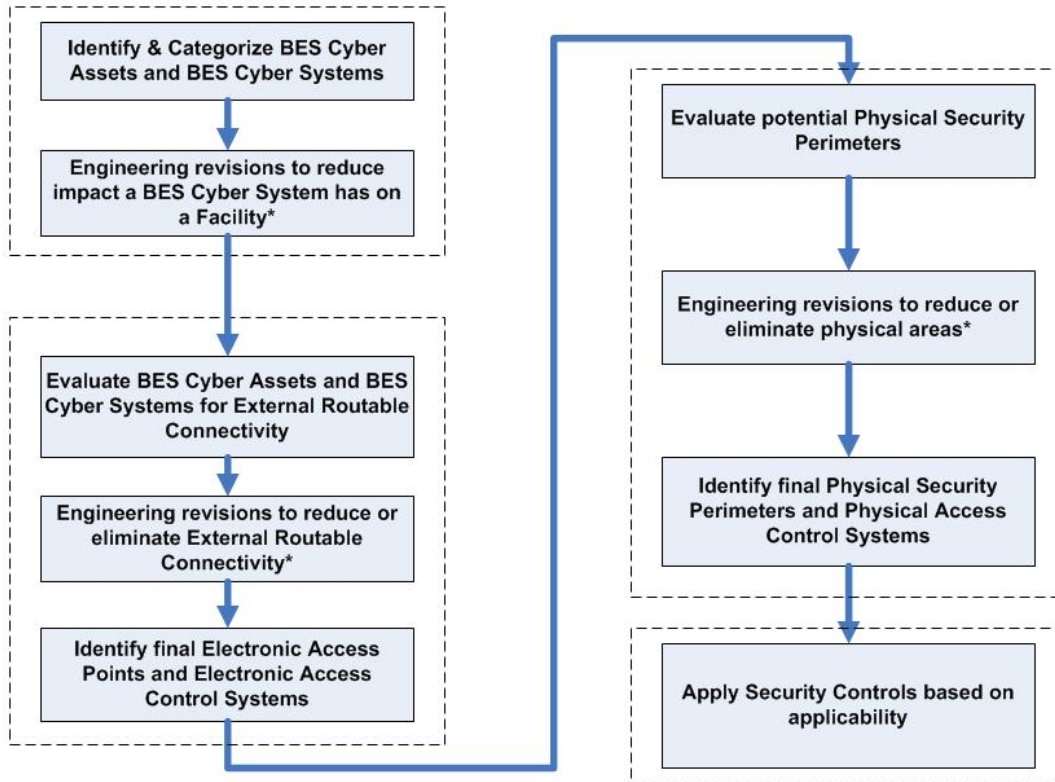
Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review,

develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard.

<u>Completed Actions</u>	<u>Date</u>
<u>Standards Committee approved Standard Authorization Request (SAR) for posting</u>	<u>March 9, 2016</u>
<u>SAR posted for comment</u>	<u>March 23 - April 21, 2016</u>
<u>SAR posted for comment</u>	<u>June 1 – June 30, 2016</u>
<u>Informal comment period</u>	<u>March 14, 2017 – April 11, 2017</u>
<u>45-day formal comment period with initial ballot</u>	<u>September 14 – October 30, 2017</u>
<u>45-day formal comment period with additional ballot</u>	<u>March 16 – April 30, 2018</u>

<u>Anticipated Actions</u>	<u>Date</u>
<u>45-day formal comment period with additional ballot</u>	<u>May 18 – July 2, 2018</u>
<u>10-day final ballot</u>	<u>July 30 – August 8, 2018</u>
<u>NERC Board</u>	<u>August 16, 2018</u>

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See implementation plan for CIP-002-6.

6. Planned and Unplanned Changes: If a Responsible Entity has a Planned Change¹ or Unplanned Change,² the Responsible Entity shall comply with the requirements in this Reliability Standard in accordance with the following:

For Planned Changes resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard upon the commissioned date of the Planned Change. For this provision, the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES. For requirements that contain periodic obligations, initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.

For Unplanned Changes, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below. As used in the table, the phrase “BES asset type” refers to the following BES asset

¹ Planned Changes refer to changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity’s awareness. Planned Changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen by the Responsible Entity. Examples of Planned Changes include: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² Unplanned Changes refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity’s awareness or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of Unplanned Changes include: (1) when a Responsible Entity is notified (internally or externally) that a generation Facility has been designated as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year (CIP-002, Attachment 1, Criterion 2.3); (2) when a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified as critical to the derivation of an IROL and their associated contingencies (CIP-002, Attachment 1, Criterion 2.6); (3) when a generating resource that is connected at less than 100kV is designated as a new Blackstart Resource along with its Cranking Path (CIP-002, Attachment 1, Criterion 3.4); or (4) when a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in Criterion 2.10 of CIP-002, Attachment 1.

types listed in Requirement R1 of CIP-002: (i) Control Centers or backup Control Centers; (ii) Transmission stations or substations; (iii) generation resources; (iv) systems and facilities critical to system restoration including Blackstart Resources and Cranking Paths and initial switching requirements; (v) Special Protection Systems that support the reliable operation of the Bulk Electric System; and (vi) the Distribution Provider Protection Systems specified in Applicability section 4.2.1.

Scenario of Unplanned Change	Implementation Period
<u>New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type</u>	<u>12 calendar months from the date of notification or detection of the Unplanned Change.</u>
<u>New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type</u>	<u>24 calendar months from the date of notification or detection of the Unplanned Change.</u>
<u>New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type</u>	<u>12 calendar months from the date of notification or detection of the Unplanned Change.</u>
<u>New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type</u>	<u>24 calendar months from the date of notification or detection of the Unplanned Change.</u>
<u>New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type</u>	<u>12 calendar months from the date of notification or detection of the Unplanned Change.</u>
<u>New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type</u>	<u>24 calendar months from the date of notification or detection of the Unplanned Change.</u>

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above, except that the Responsible Entity shall initially perform Part 2.2 of Requirement R2 by the date the Implementation Period ends where the Unplanned Change results in a high or medium impact BES Cyber System and the Responsible Entity previously had neither a high nor a medium impact BES Cyber System.

For Unplanned Changes resulting in a higher categorization for an existing BES Cyber System, the Responsible Entity shall continue to comply with the applicable

requirements of the prior categorization during the Implementation Period defined above.

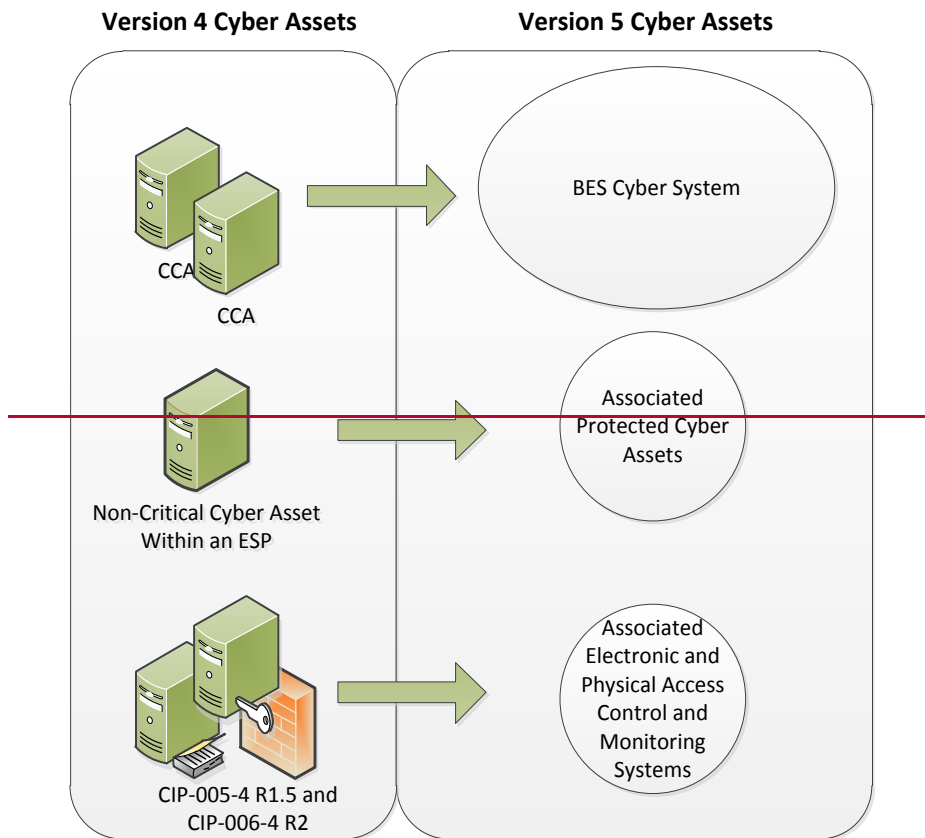
6.7. Background: This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

Another reason for using the The term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-

developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these ~~Version 5~~ CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES

Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.1~~3~~⁴ default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the ~~Version 5~~ CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002- 5-4a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6-4a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6-4a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6-4a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more

implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry's overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

~~Among other issues, due~~ Due to the ongoing confusion of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center's associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center's associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

- 2.12.** Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

~~At NERC's direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.~~

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)

- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11-13 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a

line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified

as a result of a “long term” reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate

generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion,

additional qualifications that would ensure the required level of impact to the BES. The drafting team:

- Excluded radial facilities that would only provide support for single generation facilities.
- Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated

weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300

MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission

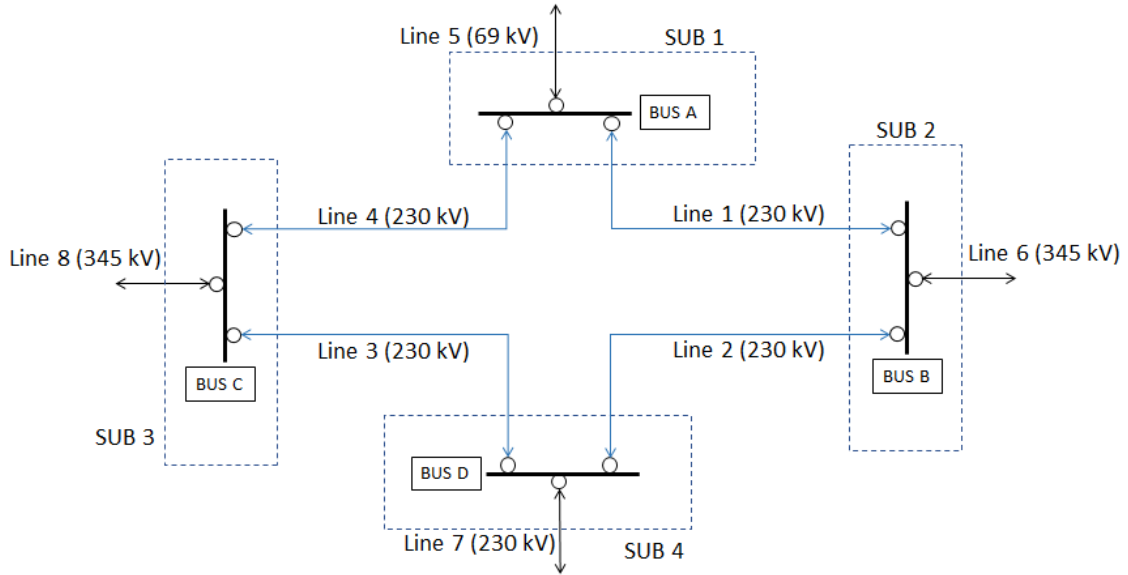
Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

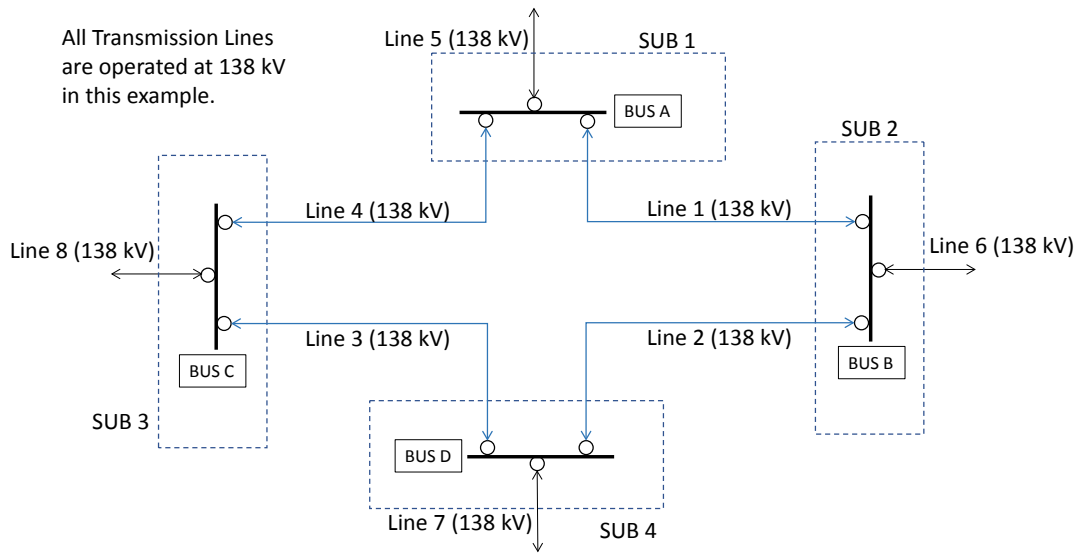
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A

100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration

assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

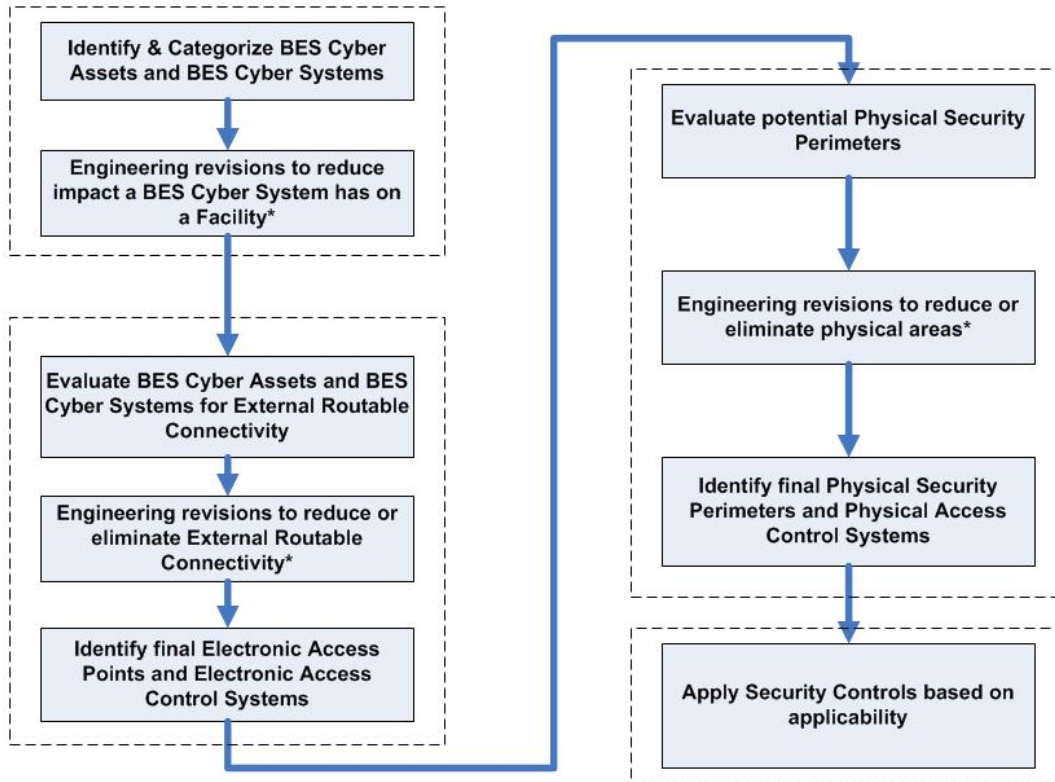
Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review,

develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is three (3) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is three (3) calendar months after sixty (60) days following the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned and Unplanned Changes

~~Planned changes refer to any changes of the electric system or BES Cyber System as identified through the assessment under CIP-002-6, Requirement R2, which were planned and implemented by the responsible entity.~~

~~For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the applicable CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.~~

~~In contrast, unplanned changes refer to any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.~~

~~For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System, and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System. For example, initial performance shall be within 15 months following the update of the identification and categorization of the affected BES Cyber System for requirements that must be performed at least once every 15 calendar months.~~

~~For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System.~~

Scenario of Unplanned Changes	Compliance Implementation
New high impact BES Cyber System	12 months

New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System from low impact BES Cyber System	12 months
Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)	24 months

For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is three (3) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is three (3) calendar months after sixty (60) days following the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned and Unplanned Changes

~~Planned changes refer to any changes of the electric system or BES Cyber System as identified through the assessment under CIP-002-6, Requirement R2, which were planned and implemented by the responsible entity.~~

~~For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the applicable CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.~~

~~In contrast, unplanned changes refer to any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.~~

~~For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System, and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System. For example, initial performance shall be within 15 months following the update of the identification and categorization of the affected BES Cyber System for requirements that must be performed at least once every 15 calendar months.~~

~~For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System.~~

Scenario of Unplanned Changes	Compliance Implementation
New high impact BES Cyber System	12 months

New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System from low impact BES Cyber System	12 months
Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)	24 months

For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards CIP-002-6 – Transmission Owner (TO) Control Center (TOCC) Performing Transmission Operator (TOP) Obligations

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments on the **Transmission Owner Control Center performing Transmission Operator obligations**. The electronic form must be submitted by **8 p.m. Eastern, April 30, 2018**.

Additional information is available on the [project page](#). If you have questions, contact [Jordan Mallory](#) at (404) 446-2589 or [Mat Bunch](#) at (404) 446-9785.

Background Information

Project 2016-02 (1) addresses the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822 and (2) considers the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document).

The V5TAG, which consisted of representatives from NERC, Regional Entities and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP Version 5 standards and to support industry's implementation activities. During the V5TAG's activities, it identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the [CIP Version 5 Transition Advisory Group Issues for Consideration](#) document to formally recommend that the SDT address these issues and consider modifications to the standard language during the standards development process. Among other issues of the V5TAG recommended clarification of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12. The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12. The aggregate weighted value is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the BES Cyber System(s) exceeds the 6000 aggregate weighted value, it should be identified as a medium impact BES Cyber System. If the BES Cyber System does not exceed the 6000 aggregate weighted value, it should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

SDT Approach

The Project 2016-02 SDT proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements for a TO Control Center that performs the functional obligations of a TOP. The proposed criterion establishes a minimum threshold for medium impact BES Cyber Systems used by and located at Control Centers that monitor and control BES Transmission Lines regardless of a Responsible Entity's functional registration. This allows TOs and TOPs to identify their BES Cyber Systems, used by and located at Control Centers, as medium or low impact based on the BES Cyber System's span of control. This contrasts with the currently approved Criterion 2.12, which identifies BES Cyber Systems used by and located at a Control Center or backup Control Center that is used to perform the functional obligations of the TOP that is not included in high impact rating, as medium impact BES Cyber Systems.

Questions

1. Criterion 2.12: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

2. Effective Date: Do you agree with the proposed modifications in CIP-002-6 to address the implementation timelines for planned and unplanned changes? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

3. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is three (3) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

- Yes
 No

Comments:

4. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Yes

No

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	Medium
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity’s CIP management program.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The VRF is not being modified for this requirement. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity’s CIP management program. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1

Proposed VRF	Medium
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1

Lower	Moderate	High	Severe
<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high or</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</p>

<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
---	--	---	---

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	
--	---	---	--

VSL Justifications for CIP-002-6 Requirements R1

<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a:</u> The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b:</u> Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.</p>

<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.</p>
---	--

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	Medium
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity’s CIP management program.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The VRF is not being modified for this requirement. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. <u>A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity’s CIP management program.</u> The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1

Proposed VRF	Medium
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1

Lower	Moderate	High	Severe
<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high or</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</p>

<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
---	--	---	---

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	
--	---	---	--

VSL Justifications for CIP-002-6 Requirements R1

<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a:</u> The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b:</u> Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.</p>

<p>FERC VSL G4</p> <p>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.</p>
--	--

Project 2016-02 Consideration of Issues and Directives

CIP V5 Issues for Standard Drafting Team Consideration¹

From experience in the V5 Transition Study and the on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty in implementation of the requirements. In many cases, the V5TAG members found that select language within the CIP Version 5 standards may be understood in multiple ways. These interpretations appear to go beyond the intended flexibility of the standard language that is necessary to accommodate the diverse nature of facts and circumstances across the electric sector.

The Standard Drafting Team modified Standard CIP-002-6 to address the issue of Transmission Owner (TO) Control Centers performing the functional obligations of the Transmission Operator (TOP).

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.	The Project 2016-02 Standard Drafting Team (SDT) revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 to address all Control Centers or backup Control Centers of Transmission, regardless of registration. The revision provides a bright line threshold that categorizes BES Cyber Systems used by and located at Control Centers of Transmission as medium impact.

¹ http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
	The reference to Transmission Operator has been removed to provide clarity.
Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the “CIP-002-5” section paragraph starting with “Responsibility for the reliable operation of the BES is spread across all Entity Registrations”; the table following that paragraph; the “High Impact Rating (H)” section; and the criterion bullets for Control Centers under the “Medium Impact Rating (M)” section.	The revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems used by and located at Control Centers of Transmission as medium impact. All other BES Cyber Systems associated with Control Centers of Transmission that do not meet the bright line threshold will be categorized as low impact. Based on this categorization, the requirements applicable to the Control Center’s BES Cyber Systems are clearly defined through the Applicable Systems language throughout Standards CIP-003 through CIP-011.
The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include ‘Control Center’, for example, the revised Glossary term for “System Operator” to be effective July 1, 2016).	The SDT is considering revisions to the definition of Control Center, but asserts that the modifications to Criterion 2.12 of CIP-002-6, Attachment 1 effectively address the concerns raised by the V5TAG regarding Transmission Owner Control Centers.
The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.	The SDT contends that the issue raised by the V5TAG is uniquely associated with small Transmission Owner Control Centers and Transmission Operator Control Centers (criterion 2.12), and therefore has determined that Reliability Standard CIP-002-5.1a, Attachment 1, Criteria 1.1, 1.2, 1.3, 1.4, 2.11, and 2.13 are sufficiently clear and do not need modification.

Project 2016-02 Consideration of Issues and Directives

CIP V5 Issues for Standard Drafting Team Consideration¹

From experience in the V5 Transition Study and the on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty in implementation of the requirements. In many cases, the V5TAG members found that select language within the CIP Version 5 standards may be understood in multiple ways. These interpretations appear to go beyond the intended flexibility of the standard language that is necessary to accommodate the diverse nature of facts and circumstances across the electric sector.

The Standard Drafting Team modified Standard CIP-002-6 to address the issue of Transmission Owner (TO) Control Centers performing the functional obligations of the Transmission Operator (TOP).

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.	The Project 2016-02 Standard Drafting Team (SDT) revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 to address all Control Centers or backup Control Centers of Transmission, regardless of registration. The revision provides a bright line threshold that categorizes <u>BES Cyber Systems used by and located at</u> Control Centers <u>of Transmission containing BES</u>

¹ http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
	Cyber Systems to be categorized as medium impact. The reference to Transmission Operator has been removed to provide clarity.
<p>Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the “CIP-002-5” section paragraph starting with “Responsibility for the reliable operation of the BES is spread across all Entity Registrations”; the table following that paragraph; the “High Impact Rating (H)” section; and the criterion bullets for Control Centers under the “Medium Impact Rating (M)” section.</p>	<p>The revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems <u>used by and located at associated with</u> Control Centers of Transmission as medium impact. All other BES Cyber Systems associated with Control Centers of Transmission that do not meet<u>exceed</u> the bright line threshold will be categorized as low impact. Based on this categorization, the requirements applicable to the Control Center’s BES Cyber Systems are clearly defined through the Applicable Systems language throughout Standards CIP-003 through CIP-011.</p>
<p>The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include ‘Control Center’, for example, the revised Glossary term for “System Operator” to be effective July 1, 2016).</p>	<p>The SDT is considering revisions to the definition of Control Center, but asserts that the modifications to Criterion 2.12 of CIP-002-6, Attachment 1 effectively address the concerns raised by the V5TAG regarding Transmission Owner Control Centers.</p>
<p>The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.</p>	<p>The SDT contends that the issue raised by the V5TAG is uniquely associated with small Transmission Owner Control Centers and Transmission Operator Control Centers (<u>criteria 2.12</u>), and <u>therefore has determined that</u> Reliability Standard CIP-002-5.1a,</p>

Issues from CIP V5 Issues for Standard Drafting Team Consideration

Issue Language	Consideration of Issue
	Attachment 1, Criteria 1.1, 1.2, 1.3, 1.4, 2.11, and 2.13 are sufficiently clear and do not need modification.

Standards Announcement

Reminder

Project 2016-02 Modifications to CIP Standards

Initial and Additional Ballots and Non-binding Polls Open through April 30, 2018

[Now Available](#)

Initial ballots for the **Control Center Definition** and its **Implementation Plan**, additional ballots for **CIP-002-6** and **CIP-012-1** and the associated non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, April 30, 2018**.

The standard drafting team's considerations of the responses received from the last comment period for **CIP-002-6** and **CIP-012-1** are reflected in these drafts of the standards.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) [here](#). If you experience any difficulties navigating the SBS, contact [Wendy Muller](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS is **not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Note: If a member cast a vote in the previous ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact [Mat Bunch](#) at (404) 446-9785 or [Jordan Mallory](#) at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Periods Open through April 30, 2018
Ballot Pools Forming through April 16, 2018

[Now Available](#)

Three formal comment periods are open through **8 p.m. Eastern, Monday, April 30, 2018** for:

1. **CIP-002-6 – Cyber Security - BES Cyber System Categorization**
2. **CIP-012-1 – Cyber Security - Communications between Control Centers**
3. **Project 2016-02 Modifications to NERC Glossary of Terms Used in Reliability Standards – Control Center**

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience difficulties navigating the SBS, contact [Wendy Muller](#). Unofficial Word versions of the comment forms are posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, April 16, 2018** for the **Control Center Definition** and its **Implementation Plan**. Registered Ballot Body members can join the ballot pools [here](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS is **not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The initial ballots for the **Control Center Definition** and its **Implementation Plan** will be conducted **April 20-30, 2018**. Additional ballots for **CIP-002-6** and **CIP-012-1** and the associated non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 20-30, 2018**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact [Mat Bunch](#) at (404) 446-9785 or [Jordan Mallory](#) at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Periods Open through April 30, 2018
Ballot Pools Forming through April 16, 2018

[Now Available](#)

Three formal comment periods are open through **8 p.m. Eastern, Monday, April 30, 2018** for:

1. **CIP-002-6 – Cyber Security - BES Cyber System Categorization**
2. **CIP-012-1 – Cyber Security - Communications between Control Centers**
3. **Project 2016-02 Modifications to NERC Glossary of Terms Used in Reliability Standards – Control Center**

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience difficulties navigating the SBS, contact [Wendy Muller](#). Unofficial Word versions of the comment forms are posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, April 16, 2018** for the **Control Center Definition** and its **Implementation Plan**. Registered Ballot Body members can join the ballot pools [here](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS is **not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The initial ballots for the **Control Center Definition** and its **Implementation Plan** will be conducted **April 20-30, 2018**. Additional ballots for **CIP-002-6** and **CIP-012-1** and the associated non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 20-30, 2018**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact [Mat Bunch](#) at (404) 446-9785 or [Jordan Mallory](#) at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Comment: [View Comment Results](#)

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 AB 2 ST

Voting Start Date: 4/20/2018 12:01:00 AM

Voting End Date: 4/30/2018 8:00:00 PM

Ballot Type: ST

Ballot Activity: AB

Ballot Series: 2

Total # Votes: 256

Total Ballot Pool: 315

Quorum: 81.27

Weighted Segment Value: 93.31

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	55	0.859	9	0.141	1	6	11
Segment: 2	7	0.4	4	0.4	0	0	0	2	1
Segment: 3	76	1	51	0.927	4	0.073	0	3	18
Segment: 4	23	1	17	1	0	0	0	0	6
Segment: 5	68	1	46	0.92	4	0.08	0	3	15
Segment: 6	49	1	34	0.872	5	0.128	0	2	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	315	6.3	216	5.878	22	0.422	1	17	59

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Lisa Martin		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A

5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		None	N/A
3	Piedmont EMC	Lawrence Hopkins Jr		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A

1	Colorado Springs Utilities	Devin Elverdi	Affirmative	N/A
6	Seattle City Light	Charles Freeman	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	Affirmative	N/A
3	Seattle City Light	Laurie Hammack	None	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon	Affirmative	N/A
1	Salt River Project	Chris Hofmann	None	N/A
5	AEP	Thomas Foltz	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Abstain	N/A
6	Austin Energy	Andrew Gallo	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Affirmative	N/A
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro	Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad	Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative
1	Long Island Power Authority	Robert Ganley	None	N/A
5	Seattle City Light	Faz Kasraie	None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski	Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines	Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy	None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Affirmative	N/A
5	Great River Energy	Preston Walsh	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
3	Cowlitz County PUD	Russell Noble	Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason	Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith	None	N/A
5	Nebraska Public Power District	Don Schmit	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey	None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton	Affirmative	N/A
5	Acciona Energy North America	George Brown	Affirmative	N/A
5	MEAG Power	Steven Grego	Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain

3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Harold Sherrill	None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Dawn Hamdorf	Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A

6	Muscatine Power and Water	Ryan Streck	Amie Shuger McConnaha	Affirmative N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative N/A
3	Ameren - Ameren Services	David Jendras		Affirmative N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative N/A
1	KAMO Electric Cooperative	Micah Breedlove		None N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative N/A
5	New York Power Authority	Erick Barrios		Affirmative N/A
3	Puget Sound Energy, Inc.	Tim Womack		None N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative Comments Submitted
1	Duke Energy	Laura Lee		Affirmative N/A
1	National Grid USA	Michael Jones		Affirmative N/A
3	Clark Public Utilities	Jack Stamper		None N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative N/A
3	New York Power Authority	David Rivera		Affirmative N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative N/A
5	Seminole Electric Cooperative, Inc.	David Weber		None N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain N/A
3	Rutherford EMC	Tom Haire		None N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative N/A

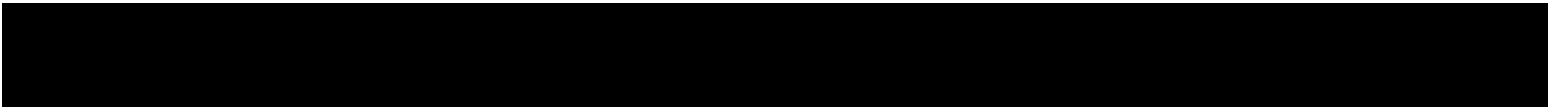
5	Associated Electric Cooperative, Inc.	Brad Haralson	None	N/A
3	Georgia System Operations Corporation	Scott McGough	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette	Abstain	N/A
3	Platte River Power Authority	Jeff Landis	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative Comments Submitted
5	Northern California Power Agency	Marty Hostler	Affirmative	N/A
1	M and A Electric Power Cooperative	William Price	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	None	N/A
2	California ISO	Richard Vine	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott	None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman	Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer	Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder	Affirmative	N/A
5	Black Hills Corporation	George Tatar	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett	Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	None	N/A
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert	None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Negative	No Comment Submitted
3	Manitoba Hydro	Karim Abdel-	Affirmative	N/A

		Hadi		
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative N/A
1	Lakeland Electric	Larry Watt		Affirmative N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative N/A
3	Black Hills Corporation	Eric Egge		Affirmative N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative N/A
8	David Kiguel	David Kiguel		Affirmative N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative N/A
3	National Grid USA	Brian Shanahan		Affirmative N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative N/A
3	Public Utility District No. 1 of Okanogan County	Dale Duncel		None N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative N/A
5	JEA	John Babik		None N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative N/A
3	JEA	Garry Baker		None N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative N/A
6	Westar Energy	Megan Wagner		Affirmative N/A
3	Westar Energy	Bo Jones		Affirmative N/A
1	Westar Energy	Kevin Giles		Affirmative N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative Comments Submitted

1	Black Hills Corporation	Wes Wingen	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
5	Westar Energy	Laura Cox	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	N/A
5	NB Power Corporation	Laura McLeod	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson	None	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman	Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne	Abstain	N/A
4	LaGen	Richard Comeaux	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	None	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	N/A
3	AEP	Aaron Austin	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Affirmative N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative N/A

6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
6	Lakeland Electric	Paul Shipp		Negative	Third-Party Comments
4	City of Clewiston	Lynne Mila		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Jeff Johnson	None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	Intermountain REA	David Maier		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	James Anderson		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Santee Cooper	Chris Wagner		None	N/A
6	Santee Cooper	Marty Watson		None	N/A
3	Santee Cooper	James Poston		None	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
4	National Rural Electric Cooperative Association	Barry Lawson		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A

1	Peak Reliability	Michael Granath	None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Abstain	N/A



[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 Non-binding Poll AB 2 NB

Voting Start Date: 4/20/2018 12:01:00 AM

Voting End Date: 4/30/2018 8:00:00 PM

Ballot Type: NB

Ballot Activity: AB

Ballot Series: 2

Total # Votes: 224

Total Ballot Pool: 282

Quorum: 79.43

Weighted Segment Value: 93.22

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	39	0.886	5	0.114	15	13
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	69	1	40	0.976	1	0.024	11	17
Segment: 4	19	1	13	1	0	0	1	5
Segment: 5	61	1	33	0.917	3	0.083	9	16
Segment: 6	44	1	28	0.903	3	0.097	7	6
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment:	6	0.5	5	0.5	0	0	1	0
Totals:	282	6.2	165	5.882	12	0.318	47	58

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Lisa Martin		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A

6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		None	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A

1	Salt River Project	Chris Hofmann	None	N/A	
5	AEP	Thomas Foltz	Affirmative	N/A	
6	Austin Energy	Andrew Gallo	Affirmative	N/A	
2	PJM Interconnection, L.L.C.	Mark Holman	Abstain	N/A	
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Abstain	N/A	
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Affirmative	N/A	
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A	
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Affirmative	N/A	
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro	Affirmative	N/A	
3	Silicon Valley Power - City of Santa Clara	Val Ridad	Affirmative	N/A	
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Long Island Power Authority	Robert Ganley	None	N/A	
5	Seattle City Light	Faz Kasraie	None	N/A	
4	WEC Energy Group, Inc.	Anthony Jankowski	Affirmative	N/A	
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A	
3	Portland General Electric Co.	Angela Gaines	Affirmative	N/A	
5	Puget Sound Energy, Inc.	Lynn Murphy	None	N/A	
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Affirmative	N/A	
5	Great River Energy	Preston Walsh	Affirmative	N/A	
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A	
3	Cowlitz County PUD	Russell Noble	Affirmative	N/A	
6	Portland General Electric Co.	Daniel Mason	Affirmative	N/A	
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A	
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A	
6	TECO - Tampa Electric Co.	Benjamin Smith	None	N/A	
5	Nebraska Public Power District	Don Schmit	Abstain	N/A	
3	TECO - Tampa Electric Co.	Ronald Donahey	None	N/A	
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton	Abstain	N/A	
5	Acciona Energy North America	George Brown	Abstain	N/A	
5	MEAG Power	Steven Grego	Abstain	N/A	
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A	
1	Eversource Energy	Quintin Lee	Affirmative	N/A	
5	Herb Schrayshuen	Herb Schrayshuen	Affirmative	N/A	
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Harold Sherrill	None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd	None	N/A	
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A	

5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Dawn Hamdorf	Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
6	Muscatine Power and Water	Ryan Streck	Amie Shuger McConnaha	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	City of Farmington	Linda Jacobson- Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A

5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Ellen Oswald		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A

1	Ameren - Ameren Services	Eric Scott	Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel	None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis	Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	Affirmative	N/A
5	JEA	John Babik	None	N/A
6	Great River Energy	Donna Stephenson	Affirmative	N/A
3	JEA	Garry Baker	None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short	Affirmative	N/A
6	Westar Energy	Megan Wagner	Affirmative	N/A
3	Westar Energy	Bo Jones	Affirmative	N/A
1	Westar Energy	Kevin Giles	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash	Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
5	Westar Energy	Laura Cox	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	N/A
5	NB Power Corporation	Laura McLeod	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Abstain	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson	None	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman	Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Abstain	N/A
6	Black Hills Corporation	Eric Scherr	None	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank	None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Abstain	N/A
6	Luminant - Luminant Energy	Brenda	Affirmative	N/A

		Hampton		
3	AEP	Aaron Austin		Affirmative N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative N/A
1	Lincoln Electric System	Danny Pudenz		Abstain N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative N/A
6	Lakeland Electric	Paul Shipps		Negative Comments Submitted
4	City of Clewiston	Lynne Mila		Affirmative N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Jeff Johnson	None N/A
4	American Public Power Association	Jack Cashin		None N/A
5	Oglethorpe Power Corporation	Donna Johnson		None N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative Comments Submitted
1	Lower Colorado River Authority	Michael Shaw		Affirmative N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain N/A
1	Santee Cooper	Chris Wagner		None N/A
6	Santee Cooper	Marty Watson		None N/A
3	Santee Cooper	James Poston		None N/A
5	Santee Cooper	Tommy Curtis		None N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative N/A
3	Salt River Project	Robert Kondziolka		Affirmative N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None N/A
5	City of Independence, Power and Light Department	Jim Nail		None N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain N/A
1	Muscatine Power and Water	Andy Kurriger		Abstain N/A
1	Peak Reliability	Michael Granath		None N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative N/A

3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A



Comment Report

Project Name: 2016-02 Modifications to CIP Standards | CIP-002-6 Draft 2
Comment Period Start Date: 3/16/2018
Comment Period End Date: 4/30/2018
Associated Ballots: 2016-02 Modifications to CIP Standards CIP-002-6 AB 2 ST

There were 52 sets of responses, including comments from approximately 150 different people from approximately 105 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Criterion 2.12: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

2. Effective Date: Do you agree with the proposed modifications in CIP-002-6 to address the implementation timelines for planned and unplanned changes? If not, please provide your rationale and an alternate proposal.

3. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is three (3) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

4. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	3	RF	FirstEnergy Corporation	Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Colby Bellville	Colby Bellville		FRCC,RF,SERC	Duke Energy	Doug Hills	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurie Hammack	Seattle City Light	3	WECC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
Lower Colorado River Authority	Michael Shaw	1		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company -	3	SERC

						Alabama Power Company		
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion, NextEra and HQ	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO

					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Steve Keller	Soutwest Power Pool Inc	2	SPP RE
					Sean Simpson	Board of Public Utilities, City of Mcpherson, Kansas	NA - Not Applicable	SPP RE
					louis Guidry	Cleco	1,3,5,6	SPP RE
Associated Electric	Todd Bennett	3		AECI	Michael Bax	Central Electric Power	1	SERC

Cooperative,
Inc.

	Cooperative (Missouri)		
Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
Stephen Pogue	M and A Electric Power Cooperative	3	SERC
William Price	M and A Electric Power Cooperative	1	SERC
Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
Ted Hilmes	KAMO Electric Cooperative	3	SERC
Walter Kenyon	KAMO Electric Cooperative	1	SERC
Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC

					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
--	--	--	--	--	---------------	---------------------------------------	---	------

1. Criterion 2.12: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

While the SDT recognized oDominion Energy's previous comment, a response has not been provided. As previously asked, "The use of an aggregate weighted value of 6000 contains no justified rationale and appears to be an arbitrary selection. There is no methodology provided that demonstrates how the value is derived."

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only servers to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer No

Document Name

Comment

ITC believes the criteria should be set at 3000 (to match criterion 2.5). Under the proposed 6000 point criterion entities with a high number of 100KV lines (up to 23) would have control centers excluded from Medium impact criteria and thus would not have to meet most CIP security requirements.

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

No. For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only serves to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: "Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]", which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

No

Document Name

Comment

No

The proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators that currently have medium impact BES Cyber Systems because of 2.12; to become low impact.

For example:

- The use of the term "and" means that a TO that monitors **but does not control** is no longer classified as a medium BES Cyber Asset.

. A TO that monitors and control a substation (A) that has three 345 kV lines and two 138 kV lines. Its “aggregated weighted value” would be $1300+1300+1300+250+250=4,400$. This TO also monitors and controls another substation (B) with one 345 kV lines and one 138 kV lines. Its “aggregated weighted value” would be $1300+250=1,550$. $4,400 (A)+1,550 (B) =5,950$, which is less than 6,000. Therefore, even though this TO may meet the definition of Control Center, the Control Center’s BES Cyber Systems would now be low impact even though the substation itself would have medium impact BES Cyber Systems (medium impact criteria 2.5).

Texas RE inquires as to whether this is the intent of the SDT.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

No

Document Name

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the following methodology:

BES Cyber Systems are to be rated as high, medium, or low impact as follows:

- A high impact BES Cyber System is a Control Center that has one or more of the following characteristics:
 - Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact.
 - Supports generation with an aggregate capacity greater than 3000MW;
 - Supports a sum greater than 2500kV of transmission lines above 230kV;
 - Is used to operate transmission lines of 500kV or above;
- A medium impact BES Cyber System has one or more of the following characteristics:
 - Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more.
 - Supports a sum between 1500 – 2500kV of transmission lines above 230kV;
 - Supports generation with the aggregate capacity between 1500 – 3000MW;
- A low impact BES Cyber System has one or more of the following characteristics:
 - Supports a sum less than 1500kV of transmission lines above 230kV;
 - Supports transmission only between 110 – 230kV;
 - Supports generation with an aggregate capacity between 75 – 1500MW;
 - Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System;

- Supports any Facilities that are designated a blackstart resource;
- Supports any other RAS not already identified as a medium impact BES Cyber System.

Likes 0

Dislikes 0

Response

Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer Yes

Document Name

Comment

City Light supports APPA comments

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer Yes

Document Name

Comment

One, we agree with establishing a threshold criterion for 2.12. We would like the Standards Drafting Team to provide some background regarding the technical basis for setting the threshold at the 6000 aggregate weighted value for applicable BES Cyber Systems. Two, though we are voting affirmative, we respectfully request the SDT to not ballot CIP-002 again until the Control Center definition has passed. If the Control Center definition is

not resolved by the next ballot on CIP-002, we will consider a negative vote. This is because the Control Center definition is the foundation for the Attachment 1 criteria for Control Centers. Approving a standard without clarity of the foundation term is not advisable.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

Yes

Document Name

Comment

NVE agrees with modification of the criterion. For industry reference, we do believe rationalization for 6000 point threshold should be made available within the Attachment, or through industry outreach (Technical justification document, Industry webinar, etc.)

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer

Yes

Document Name

Comment

No comment

Likes 0

Dislikes 0

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer

Yes

Document Name

Comment	
No Comment	
Likes	0
Dislikes	0
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
<p>We agree with revising this criterion to be a threshold based analysis, and feel it provides a good objective criteria to determine in scope assets. We would like the Standards Drafting Team to provide some background regarding the technical basis for setting the threshold at the 6000 aggregate weighted value for applicable BES Cyber Systems.</p> <p>Also, we'd like the Standards Drafting Team to consider timing when posting CIP-002-6 for final ballot. Without the Control Center definition being resolved and approved prior to the final approval for CIP-002-6, we will consider a negative vote on CIP-002-6. This is because the Control Center definition is the foundation for the Attachment 1 criteria for Control Centers, and would not be advisable to approve the standard without clarity of the term.</p>	
Likes	0
Dislikes	0
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
<p>One, we agree with establishing a threshold criterion for 2.12. We would like the Standards Drafting Team to provide some background regarding the technical basis for setting the threshold at the 6000 aggregate weighted value for applicable BES Cyber Systems. Two, though we are voting affirmative, we respectfully request the SDT to not ballot CIP-002 again until the Control Center definition has passed. If the Control Center definition is not resolved by the next ballot on CIP-002, we will consider a negative vote. This is because the Control Center definition is the foundation for the Attachment 1 criteria for Control Centers. Approving a standard without clarity of the foundation term is not advisable.</p>	
Likes	0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Yes, without additional comment.

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Proposed modifications are accepted. No impact on existing categorization of SRP BES Cyber Systems at control centers. SRP control center(s) are categorized "High Impact" due to Criterion 1.1-1.4, hence Criterion 2.12 is not applicable

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jonathan Aragon - APS - Arizona Public Service Co. - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Faz Kasraie - Seattle City Light - 5 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Glen Farmer - Avista - Avista Corporation - 1,3,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Gordon - Massachusetts Municipal Wholesale Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrey Komissarov - Sempra - San Diego Gas and Electric - 7 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Dmitriy Bazilyuk - NiSource - Northern Indiana Public Service Co. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jack Cashin - American Public Power Association - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, NextEra and HQ

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports comments provided by NRECA

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response

Likes 0

Dislikes 0

Response

2. Effective Date: Do you agree with the proposed modifications in CIP-002-6 to address the implementation timelines for planned and unplanned changes? If not, please provide your rationale and an alternate proposal.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, NextEra and HQ

Answer No

Document Name

Comment

Update says

<<

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above

>>

Request clarification on this "first period." If the obligation is quarterly and the Implementation Period is 24 months, would this first period be the first quarter after those 24 months?

Request clarification on "CIP Cyber Security Standards." Does this include only CIP-002 – CIP-011? Or more CIP Standards?

<<

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

>>

It might be pertinent that the STD takes in consideration the change in the categorization for an existing BES cyber System considered in CIP-002-6 as an unplanned changes and gives an implementation period to comply with the new applicable requirements relative to the new categorisation. A change in the categorization for an existing BES cyber System can be from Low to Medium and can involve an certain amount of new applicable requirements that can involve for an entity a certain period of time to be compliant even tough the BES Cyber system is already impacting the BES.

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer No

Document Name

Comment

“Initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.” Further clarification is needed regarding what the “first period” means. For instance, does this mean calendar quarter? Next day? Day of?

Additionally, further clarification is needed on what “impacting the BES” means with respect to, “the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES.” Does this mean that, according to the entity’s interpretation, the new or modified BES asset or Cyber Asset could, *within 15 minutes*, adversely impact the reliable operation of the BES? Or does impacting the BES mean something else ?

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

No

Document Name

Comment

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees with moving the implementation timelines for planned and unplanned changes to CIP-002-6. However, CenterPoint Energy believes the implementation timeline for planned changes resulting in a higher categorization as proposed in CIP-002-6 is not consistent with the concept in the current CIP Version 5/6 implementation plan. Paragraph 3 on page 4 of the “Implementation Plan for Version 5 CIP Cyber Security Standards” states that for planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements “**on the update of the identification and categorization of the affected BES Cyber System,**” not “upon the commission date of the planned change” as proposed in CIP-002-6.

CenterPoint Energy recommends removing the phrase “or a change in categorization for an existing BES Cyber System” from the second paragraph in section 6 to keep it focused on planned changes resulting in a new BES Cyber System and adding the following paragraph for planned changes resulting in a higher categorization:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets.”

Likes 0

Dislikes 0

Response

Sergio Banelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer

No

Document Name

Comment

Tri-State does not understand the sentence/paragraph following the Implementation Table in Section 6. For example, there's a reference to requirements with periodic obligations. Does this pertain only to those found in CIP-002 or those found throughout the CIP Standards? If it only refers to those found in CIP-002, then Tri-State would recommend explicitly stating that. Tri-State also believes the language is overly verbose and complex.

Likes 0

Dislikes 0

Response**James Anderson - CMS Energy - Consumers Energy Company - 1**

Answer

No

Document Name

Comment

Since CIP-002-5.1a became effective the SMEs responsible for evaluating and identifying Low BES Cyber Assets have incrementally increased the types of devices in scope as industry/regional expectations developed, SME changes and associated interpretations occurred, and their own CIP-002-5.1a knowledge has increased.

Adding regulation to be compliant upon installation will have the opposite effect of SMEs: who will now prefer “no change” over performing a thorough and fresh review for each CIP-002 iteration.

Likes 0

Dislikes 0

Response**Julie Hall - Entergy - 6, Group Name Entergy**

Answer

No

Document Name

Comment

The proposed Section 6 for Planned and Unplanned Changes is good. The issue is that the definitions, examples, and timeframes do not specifically address the timeframes for acquisition of an existing facility and differences between company posture. Recommend defining acquisitions as either a Planned Change, Unplanned Change, or as a separate event with timeframes.

Likes 0

Dislikes 0

Response

Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer No

Document Name

Comment

Want to see Commission date defined in the NERC Glossary of terms. Would like to see "Commission date" language to be used in the CIP-007 and CIP-010 standards that it impacts (baselining, SIEM logging, Patch Source tracking) and the language in those standards changed concurrently with the CIP-002-6. Section 6 of CIP-002-6 uses the word "this Reliability Standard" in the first sentence which implies CIP-002-6 only but the standard is impacting not just "this CIP-002" but affects other standards as well.

Likes 0

Dislikes 0

Response

David Gordon - Massachusetts Municipal Wholesale Electric Company - 5

Answer No

Document Name

Comment

MMWEC supports comments submitted by NPCC.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer No

Document Name

Comment

BPA disagrees with the location/treatment of the implementation timelines (i.e. Applicability section) for description of Planned and Unplanned Changes and associated Scenario of Unplanned Changed Implementation Period table. From an audit standpoint, BPA suggests standard template formatting and numbering be applied.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

Since CIP-002-5.1a became effective the SMEs responsible for evaluating and identifying Low BES Cyber Assets have incrementally increased the types of devices in scope as industry/regional expectations developed, SME changes and associated interpretations occurred, and their own CIP-002-5.1a knowledge has increased.

Adding regulation to be compliant upon installation will have the opposite effect of SMEs: who will now prefer “no change” over performing a thorough and fresh review for each CIP-002 iteration.

Likes 0

Dislikes 0

Response

Jonathan Aragon - APS - Arizona Public Service Co. - 6

Answer No

Document Name

Comment

AZPS recommends that the implementation time period be 24 calendar months from the date of notification or detection of the unplanned changes regardless of whether or not the Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type as the effort required would involve the design and implementation of technology, procurement, and contracting efforts, which could easily exceed 12 months.

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

1. Dominion Energy recommends converting the footnotes contained in Section 6 to NERC defined terms. This would clarify the terms in a central location and avoid confusion.

2. It is unclear why an unplanned change would warrant more time than a planned change. The risk is the same for both situations. Please provide clarification on why unplanned and planned changes have different implementation periods.
3. In some scenarios, it appears that a change may result in reclassifying a BCS which would require significant changes to meet compliance obligations.

Clarify why an entity may have a 12 month implementation plan in the case of an unplanned change, but could potentially only have a few weeks implementation plan for the entire substation if a new transmission line causes the substation to go from low to medium impact. The “few weeks” example was provided because cyber assets will likely be the last phase of a project and the substation BCS will not be complete without the new cyber assets. Additionally, all compliance related tasks would need to be completed during the same timeframe as operational installation and testing.

For planned changes, we recommend defining an implementation period not to exceed 1 year after the in-service date that allows for compliance activities to be performed.

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

If these standards would have applied to us, SRP would have discussed the timeline and impacts as a group and formed a consensus before commenting. We would have asked for additional time to prepare to meet compliance (for planning, coordination, and out other logistics).

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

Yes

Document Name

Comment

Yes, without additional comment.

Likes 0

Dislikes 0

Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Though we are voting affirmative, we respectfully request the SDT consider a revision. Planned and unplanned changes include footnotes. We recommend revising both footnotes from “Examples of ... include:” to “Examples of ... include, but are not limited to:”	
Likes	0
Dislikes	0
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
We support the proposed implementation timelines for planned and unplanned changes. However, please consider the following revision to planned and unplanned changes footnotes. We recommend revising both footnotes from “Examples of ... include:” to “Examples of ... include, but are not limited to:”	
Likes	0
Dislikes	0
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes	0
Dislikes	0

Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
<p>Yes with the following questions to be addressed:</p> <p>1.Does a new EMS need to be CIP compliant before the first cut-over test?</p> <p>2.Assuming the cut-over test in Q1 fails, does the system need to remain CIP compliant until the next test? The time between cut-over tests may be months.</p>	
Likes	0
Dislikes	0

Response	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
<p>It might be pertinent that the STD takes in consideration the change in the categorization for an existing BES cyber System considered in CIP-002-6 as an unplanned changes and gives an implementation period to comply with the new applicable requirements relative to the new categorisation. A change in the categorization for an existing BES cyber System can be from Low to Medium and can involve an certain amount of new applicable requirements that can involve for an entity a certain period of time to be compliant even tough the BES Cyber system is already impacting the BES.</p>	
Likes	0
Dislikes	0

Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA</p>	
Answer	Yes
Document Name	

Comment

No comment

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer Yes

Document Name

Comment

Xcel Energy generally agrees with the proposed timelines for implementation of planned and unplanned changes, further clarifications of what constitutes an unplanned change would be appreciated. The concern involves the potential maintenance or replacement of BES Assets in a BES System. As an example, would the replacement of a failed relay at a Medium Impact substation allow for a 12 month implementation period and remove compliance obligations for that system in that period? In order to remediate any ambiguous language in Section 6, Xcel Energy suggests changing the "Unplanned" language to read:

For Unplanned Changes, resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below....

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

NVE believed the timelines determined for planned and unplanned changes are reasonable.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer	Yes
Document Name	
Comment	
Exelon notices that the Unplanned Changes as described in the footnote, are all externally initiated changes. Are there any internally initiated changes that could also qualify as unplanned? Also, there may be unplanned changes that involve decommissioning of an asset. Should this also be expounded on here?	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Though we are voting affirmative, we respectfully request the SDT consider a revision. Planned and unplanned changes include footnotes. We recommend revising both footnotes from "Examples of ... include:" to "Examples of ... include, but are not limited to:"	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
City Light supports APPA comments	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrey Komissarov - Sempra - San Diego Gas and Electric - 7 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Glen Farmer - Avista - Avista Corporation - 1,3,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Faz Kasraie - Seattle City Light - 5 - WECC

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Aaron Austin - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Val Ridad - Silicon Valley Power - City of Santa Clara - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Linda Jacobson-Quinn - City of Farmington - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE inquires as to why the section regarding planned and unplanned changes was removed from the implementation plan. Since they no longer reside in one of the enforceable parts of the standard, this will cause confusion upon implementation. Texas RE recommends keeping this section in the implementation plan.

Texas RE also noticed that PCAs were removed from the graphic on page 7, but is still in the list of Cyber Assets on page 9.

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports comments provided by NRECA

Likes 0

Dislikes 0

Response

3. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is three (3) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

Without industry concurrence on the standard revisions, it is premature to comment on the implementation plan.

Likes 0

Dislikes 0

Response

Colby Bellville - Colby Bellville On Behalf of: Greg Cecil, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy

Answer No

Document Name

Comment

Duke Energy suggests the drafting team consider an Implementation Plan of 6 calendar months. Additional time will be necessary to identify impacted areas, and then to make necessary changes to applicable documentation. We think that 6 calendar months is a more reasonable timeframe given the potential level of work.

Likes 0

Dislikes 0

Response

Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer No

Document Name

Comment

Since the proposed changes impact other standards, we will need to rework the current processes and have adequate time for testing the new processes. Need the effective day to be at least first day of the first calendar quarter that is twelve (12) calendar months after approval.

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

Without industry concurrence on the standard revisions, it is premature to comment on the implementation plan.

Likes 0

Dislikes 0

Response

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 5

Answer

No

Document Name

Comment

The changes would likely take more time than 3 months to implement. 12 calendar months would be reasonable to make sure the processes and documentation are ready.

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer

No

Document Name

Comment

Reclamation recommends the Implementation Plan for the revised standard become effective the first day of the first calendar quarter that is 18 calendar months after the effective date of the applicable governmental authority's order approving the standard to allow entities time to apply the revised Impact Rating Criteria.

Likes 0

Dislikes 0

Response

Jonathan Aragon - APS - Arizona Public Service Co. - 6

Answer

Yes

Document Name

Comment

AZPS proposed that the first sentence following the table in Section 6 be modified to state: "With the exception of the initial implementation of CIP-002-6 as set forth in "Implementation Plan", for requirements that contain periodic obligation, initial performance of those obligations following an Unplanned Change, etc.

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Yes

Document Name

Comment

City Light supports APPA comments

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

Yes

Document Name

Comment	
<p>1. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.</p>	
Likes	0
Dislikes	0
Response	
<p>Brian Evans-Mongeon - Utility Services, Inc. - 4</p>	
Answer	Yes
Document Name	
Comment	
<p>Section 6 Planned and Unplanned changes uses the term commission date and then defines it in the next sentence. Suggest removing the term "commision date" and replacing it with "the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES". It is confusing to use a term in only one place and then applying a definition that is different than what some people may be use to.</p>	
Likes	0
Dislikes	0
Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA</p>	
Answer	Yes
Document Name	
Comment	
<p>No comment</p>	
Likes	0
Dislikes	0
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer Yes

Document Name

Comment

Tacoma Power supports comments provided by APPA.

Likes 0

Dislikes 0

Response

Jack Cashin - American Public Power Association - 4

Answer Yes

Document Name

Comment

APPA supports the proposed Implementation Plan and offer input to improve the clarity of that plan. Section 6 addressing Planned and Unplanned changes uses the term commission date and then defines it in the next sentence. Public power recommends removing the term “commision date” and replacing it with “the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES.” This change will provide sufficient clarity in implementing the Standard.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Given that the standard is directed toward moving the scope of applicability down (medium to low), Southern agrees with the proposal.

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

SRP agrees

Likes 0

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Nicholas Lauriat - Network and Security Technologies - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Leonard Kula - Independent Electricity System Operator - 2****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Aaron Austin - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Faz Kasraie - Seattle City Light - 5 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Glen Farmer - Avista - Avista Corporation - 1,3,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Douglas Johnson - American Transmission Company, LLC - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**David Gordon - Massachusetts Municipal Wholesale Electric Company - 5****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrey Komissarov - Sempra - San Diego Gas and Electric - 7 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, NextEra and HQ

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECl

Answer

Document Name

Comment

AECI supports comments provided by NRECA

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE is not opposed to the timeline set forth in the implementation plan. Please see Texas RE's comment in #2 regarding planned and unplanned changes.

Likes 0

Dislikes 0

Response

4. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Wendy Center - U.S. Bureau of Reclamation - 5

Answer No

Document Name

Comment

Reclamation recommends the simplified Impact Rating Criteria described in the response to Question 1 will provide a more cost-effective manner of categorizing BES Cyber Systems and their associated BES Cyber Assets by reducing the cost of implementing the standard and the overall impact of CIP-002-6 and allowing entities to reduce the time spent “review[ing] the identifications in Requirement R1 and its parts (and update[ing] them if there are changes identified) at least once every 15 calendar months.”

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only servers to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response

Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer No

Document Name

Comment

Would have like to see a timeframe like 14 calendar days within the “Commission Date” to comply rather than the “Commission Date”.

Likes 0

Dislikes 0

Response**Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF**

Answer

No

Document Name

Comment

For entities where TO Control Centers already meet High Impact criteria (by way of High Watermark), this clarification only servers to create additional compliance burden to determine an irrelevant criteria.

An alternate proposal to the drafted criterion would precede the Criterion with: “Where TO Control Centers are not determined to meet High Impact criteria then.....[perform aggregate weighting evaluation to determine IRC 2.12]”, which would allow an entity to avoid the unnecessary compliance burden of performing this evaluation for High Impact TO Control Centers.

Likes 0

Dislikes 0

Response**Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion**

Answer

No

Document Name

Comment

Dominion Energy is unable to respond because we are not impacted by the change for 2.12.

Likes 0

Dislikes 0

Response**Russell Martin II - Salt River Project - 1,3,5,6 - WECC**

Answer

Yes

Document Name**Comment**

This question might be applicable to entities who are expected to have planned and unplanned facilities non-compliant with CIP-002-6. Flexibility is, having the time and human resources to form compliance with CIP-002-6 before the deadlines. SRP does not expect such changes in our footprint. SRP agrees with the proposed modifications in CIP-002-6.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

Yes

Document Name**Comment**

Given that the standard is directed toward moving the scope of applicability down (medium to low), Southern agrees with the proposal.

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer

Yes

Document Name**Comment**

No comment

Likes 0

Dislikes 0

Response

Jonathan Aragon - APS - Arizona Public Service Co. - 6

Answer Yes

Document Name

Comment

AZPS agrees that the proposed modifications provide entities with flexibility to meet the reliability objectives, provided the implementation period is reasonable (i.e., 24 months). Otherwise it may require entities to expend significant resources to meet timeframes that may be unnecessarily short.

Likes 0

Dislikes 0

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Yes

Document Name

Comment

ADDITIONAL COMMENTS

1. Would a modification to an entity's procedure for categorizing BES Cyber Systems that brought in additional or medium or low impact BCAs be a "planned change" for purposes of CIP-002?
2. It is Seminole's understanding that NERC is attempting to disconnect the Guidelines and Technical Basis from being connected to the Standard as this section is not part of the Standard. The drafting team should make the Guidelines and Technical Basis a separate document.
3. Are the Appendix Interpretations part of the Standard? Are they being approved by FERC via this ballot action? If not, then they should be separated from the Standard.
4. How are interpretations attached to Standards different than the Compliance Application Notices ("CANS") that NERC used to attach but they tried to get away from attaching?

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, NextEra and HQ

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Quebec TransEnergie - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrey Komissarov - Sempra - San Diego Gas and Electric - 7 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Glen Farmer - Avista - Avista Corporation - 1,3,5****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Faz Kasraie - Seattle City Light - 5 - WECC****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Linda Jacobson-Quinn - City of Farmington - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE does not have comments on this question.

Likes 0

Dislikes 0

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer

Document Name

Comment

No Comment

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No Response

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports comments provided by NRECA

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

BPA has no comment

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

Document Name	
Comment	
City Light supports APPA comments	
Likes 0	
Dislikes 0	
Response	
Aaron Austin - AEP - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Critical Infrastructure Protection (CIP) Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization		
Date Submitted:	April 24, 2018		
SAR Requester			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404.446.2589	Email:	Jordan.mallory@nerc.net
SAR Type (Check as many as apply)			
<input type="checkbox"/> New Standard	<input type="checkbox"/> Imminent Action/ Confidential Issue (SPM Section 10)	<input type="checkbox"/> Variance development or revision	<input type="checkbox"/> Other (Please specify)
<input checked="" type="checkbox"/> Revision to Existing Standard			
<input type="checkbox"/> Add, Modify or Retire a Glossary Term			
<input type="checkbox"/> Withdraw/retire an Existing Standard			
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
<input type="checkbox"/> Regulatory Initiation	<input type="checkbox"/> NERC Standing Committee Identified	<input checked="" type="checkbox"/> Enhanced Periodic Review Initiated	<input type="checkbox"/> Industry Stakeholder Identified
<input type="checkbox"/> Emerging Risk (Reliability Issues Steering Committee) Identified			
<input type="checkbox"/> Reliability Standard Development Plan			
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
<p>The purpose of this SAR is to transfer an issue currently within the scope of Project 2015-09 (Establish and Communicate System Operating Limits) to Project 2016-02 (Modifications to CIP Standards). Transferring the issue to Project 2016-02 will simplify the standards development process for stakeholders such that only one standard drafting team (SDT) is modifying Reliability Standard CIP-002, as explained below.</p> <p>As set out in its associated SAR, the purpose of Project 2015-09 is to revise the requirements in the Facilities Design, Connections, and Maintenance (FAC) group of standards for determining and communicating System Operating Limits (SOLs) to eliminate overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).</p>			

Requested information

As relevant to this SAR, the SDT for Project 2015-09 is proposing to retire FAC-010-3 to eliminate overlap between the FAC standards and Reliability Standard TPL-001-4. With the retirement of FAC-010-3, Planning Coordinators and Transmission Planners would no longer be required to have a System Operating Limit (SOL) methodology to identify SOLs and IROLs.

Reliability Standard CIP-002-5.1a (Impact Rating Criterion 2.6 in Attachment 1), however, references IROLs identified by Planning Coordinators and Transmission Planners. The Project 2015-09 SDT concluded that there is a need to modify CIP-002-5.1a to account for the retirement of FAC-010-3 and the elimination of a requirement for planners to identify SOLs and IROLs. The Project 2015-09 SDT developed draft language to replace the reference to such IROLs in Criterion 2.6 with other language that would allow Planning Coordinators and Transmission Planners to identify Facilities that otherwise do not meet the criteria in Section 2 of Attachment 1 but pose a higher risk to reliability such that its BES Cyber Systems should be protected as Medium Impact. In addition, the Project 2015-09 SDT recommends revising the IROLs reference in Impact Rating Criterion 2.9 in Attachment 1 to CIP-002-5.1a.

Because the Project 2016-02 SDT is already modifying CIP-002-5.1a, this SAR would provide the Project 2016-02 SDT the authority to include the revisions provided by the Project 2015-09 SDT into the draft of CIP-002 to consolidate the comment period and ballot. The consolidated approach will avoid any confusion of having each SDT post the same standard for separate comment periods and ballots with different sets of changes.

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

For the reasons discussed above, with the proposed retirement of FAC-010-3, the Project 2015-09 SDT identified a need to modify CIP-002-5.1a.

Project Scope (Define the parameters of the proposed project):

The Project 2016-02 SDT, which is currently making modifications to CIP-002-5.1a, will include modifications to the IROL language located in the Impact Rating Criteria of the CIP-002-5.1a provided by the Project 2015-09 SDT.

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification¹ which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g. research paper) to guide development of the Standard or definition):

The Project 2015-09 SDT is proposing to revise the SOL/IROL-related FAC standards to reflect the notion that SOLs and IROLs should be developed and used in the operations horizon and not the planning horizon. To that end, the Project 2015-09 SDT proposes to retire the FAC-010-3 Reliability Standard, eliminating the requirement for Planning Coordinators to have a methodology for establishing SOLs for

¹ The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information

use in the planning horizon, as well as the corresponding requirements in the FAC-014-2 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs.

The Project 2015-09 SDT reviewed the Reliability Standards that this proposed change would impact and determined to propose corresponding changes to those standards. Among others, the Project 2015-09 SDT identified CIP-002-5.1a, Attachment 1, Criteria 2.6 and 2.9 as requiring modifications. The Project 2015-09 SDT proposes the following changes:

- 2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its ~~Reliability Coordinator~~, Planning Coordinator, or Transmission Planner as ~~critical to the derivation of Interconnection Reliability Operating Limits (IROLs)~~ an element of each Contingency event included in the Planning Assessment that result in System instability, Cascading, or uncontrolled separation and their associated contingencies.

- 2.9.** Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would ~~result in System instability, Cascading or uncontrolled separation~~ cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

More information on the rationale for the revisions proposed by the FAC SDT is located on the [Project 2015-09 project page](#).

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

No additional cost outside of the time and resources needed to serve on the SDT are expected. However, a question will be asked during the SAR comment period to ensure all aspects are considered.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g. Dispersed Generation Resources):

None

To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (e.g. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

Balancing Authority, certain Distribution Providers, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner

Requested information
Do you know of any consensus building activities ² in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No consensus building has been completed to date, although the subject of this SAR has been developed by the Project 2015-09 SDT under its SAR.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
The Project 2016-02 SDT is currently working on addressing Federal Energy Regulatory Commission directives and the issues identified in the Version 5 Transition Advisory Group document as set forth in its associated SAR .
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

NA

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles ?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	yes

² Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NA	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
<input checked="" type="checkbox"/> Draft SAR reviewed by NERC Staff	<input type="checkbox"/> Final SAR endorsed by the SC
<input type="checkbox"/> Draft SAR presented to SC for acceptance	<input type="checkbox"/> SAR assigned a Standards Project by NERC
<input type="checkbox"/> DRAFT SAR approved for posting by the SC	<input type="checkbox"/> SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards CIP-002-5.1a – Cyber Security – BES Cyber System Categorization Standards Authorization Request (SAR)

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System](#) to submit comments on the **Project 2016-02 Modifications to CIP Standards - IROL Modifications to CIP-002 SAR**. Comments must be submitted by **8 p.m. Eastern, Friday, July 13, 2018**.

Additional information is available on the [project page](#). If you have questions, contact [Jordan Mallory](#) (via email) or at 404-446-2589.

Background Information

This SAR transfers an issue currently within the scope of Project 2015-09 to Project 2016-02. The CIP SDT (project 2016-02) will work with the FAC SOL SDT (project 2015-09) on the modifications to CIP-002. The purpose of Project 2015-09 is to revise the requirements in the Facilities Design, Connections, and Maintenance (FAC) group standards for determining and communicating System Operating Limits (SOLs) to eliminate overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs). As part of that project, the FAC SOL SDT proposes retiring FAC-010-3 to eliminate overlap between the FAC standards and Reliability Standard TPL-001-4. With the retirement of FAC-010-3, Planning Coordinators and Transmission Planners would not be required to have a SOL methodology to identify SOLs and IROLs.

In making these modifications to the FAC Reliability Standards, the FAC SOL SDT determined CIP-002 needed revision because it references IROLs identified by Planning Coordinators and Transmission Planners. Specifically, the FAC SOL SDT recommends revising the medium impact rating criteria (2.6 and 2.9 in Attachment 1 of CIP-002) to account for the retirement of FAC-010-3. To make balloting more efficient for industry stakeholders and eliminate confusion from concurrent ballots of the same standard, NERC staff recommends balloting the changes provided by the FAC SOL SDT with the Project 2016-02 SDT revisions to CIP-002. The changes will be provided by the FAC SOL SDT and inserted by the CIP SDT into CIP-002. Because the Project 2016-02 SDT is also modifying CIP-002, NERC staff recommends consolidating the changes into one comment period and ballot. Both drafting teams will work closely together during this modification.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Yes:

No:

Comments:

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Yes:

No:

Comments:

3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Yes:

No:

Comments:

Standards Announcement

2016-02 Modifications to CIP Standards

Informal Comment Periods Open through July 13, 2018

[Now Available](#)

Informal comment periods are open through **8 p.m. Eastern, Friday, July 13, 2018**, for stakeholders to provide feedback on the **FERC Order No. 843 (Malicious Code Example)** and **IROL Modifications to CIP-002 Standards Authorization Requests**.

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience difficulty navigating the SBS, contact [Wendy Muller](#). An unofficial Word versions of the comment form is posted on the [project page](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received and determine the next steps of the project.

For more information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards | IROL Modifications to CIP-002 SAR
Comment Period Start Date: 6/14/2018
Comment Period End Date: 7/13/2018
Associated Ballots:

There were 24 sets of responses, including comments from approximately 128 different people from approximately 88 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.
2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.
3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	1,3,4	RF	FirstEnergy Corporation	Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Florida Municipal Power Agency	Brandon McCormick	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

				Seattle City Light Ballot Body	Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurie Hammack	Seattle City Light	3	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC

David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
David Kiguel	Independent	NA - Not Applicable	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Caroline Dupuis	Hydro Quebec	1	NPCC
Chantal Mazza	Hydro Quebec	2	NPCC
Gregory Campoli	New York Independent	2	NPCC

						System Operator		
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
PSEG	Sean Cavote	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Jim Williams	Southwest Power Pool Inc	2	MRO
					John Allen	City Utilities of Springfield, Missouri	4	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Steven Keller	Southwest Power Pool Inc.	2	MRO
					Alan Wahlstrom	Southwest Power Pool Inc	2	MRO
					Kim Van Brimer	Southwest Power Pool Inc	2	MRO
Associated Electric Cooperative, Inc.	Todd Bennett	1,3,5,6		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC

Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
Stephen Pogue	M and A Electric Power Cooperative	3	SERC
William Price	M and A Electric Power Cooperative	1	SERC
Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
Ted Hilmes	KAMO Electric Cooperative	3	SERC
Walter Kenyon	KAMO Electric Cooperative	1	SERC
Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
Brad Haralson	Associated Electric	5	SERC

						Cooperative, Inc.		
ACES Power Marketing	Warren Cross	2,4,5,6	MRO,RF,SERC,SPP RE,Texas RE,WECC	ACES Standards Collaborators	Arizona Electric Power Cooperative, Inc.	AEPC	1	WECC
					Hoosier Energy Rural Electric Cooperative, Inc.	HE	1	RF
					Southern Maryland Electric Cooperative	SMECO	3	RF
					North Carolina Electric Membership Corporation	NCEMC	3,4,5	SERC
					Central Iowa Power Cooperative	CIPCO	1	MRO
					East Kentucky Power Cooperative	EKPC	1,3	SERC
					Buckeye Power, Inc.	BUCK	4	RF
					Prairie Power, Inc.	PPI	1,3	SERC

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree, and, if possible, provide specific language revisions that would make it acceptable to you.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer No

Document Name

Comment

It is not necessary to change CIP-002 with the retirement of FAC-010. Identifying IROLs is still required in FAC-011-3 R1.3 and R3.7. The SAR does not refer to retirement of FAC-011-3 R1.3 and R3.7 nor retirement of the IROL definition in the NERC glossary. Therefore it is not necessary nor efficient to replace "IROL(s)" with its definition in the CIP-002 criteria 2.6 and 2.9.

Likes 0

Dislikes 0

Response

Thomas Foltz - AEP - 3,5

Answer No

Document Name

Comment

Based on its Version 5 implementation experience, AEP believes planners are trained and have the experience necessary to evaluate BES Elements and Facilities for the risks to the BES from System instability, Cascading or uncontrolled separation. They are not, however, in the best position to evaluate Cyber risk. The following should be substituted in the Requested Information Section to relay the intent: "The Project 2015-09 SDT developed draft language to replace the reference to such IROLs in Criterion 2.6 and Criterion 2.9" with other language that would allow Planning Coordinators and Transmission Planners to identify Facilities that meet the stated criteria in the proposed modifications. Project 2015-09 SDT should work with the Project 2016-02 SDT to write explicit requirements in Planning Standards for Planning Authorities to work with Responsible Entities to evaluate BES facilities for the above risks and provide for a formal appeals process.

The drafters of the FAC standards should clearly obligate, through additional or modified requirement language, for the planning authorities to provide information regarding the impact to those facilities to Generation Owners and Transmission Owners.

In the Reliability Principals Section, only item# 8 should be checked, as CIP-002 is not a planning standard.

It appears that these two proposed SARs would be applied to the project along with the existing SAR, bringing the total number of SARs for this project to three. AEP is not aware of any precedent of multiple, **concurrent** SARs governing a NERC project at a single point in time. A SAR helps set a project's direction and scope, and while a project's SAR may be revised over time, AEP does not believe Appendix 3A (Standards Process Manual) provides an allowance for multiple, concurrent SARs to govern a single NERC project. Rather, the SPM allows a project's existing SAR to be revised to accommodate any changes believed to be necessary.

Likes 0

Dislikes 0

Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
It is not necessary to change CIP-002 with the retirement of FAC-010. Identifying IROLs is still required in FAC-011-3 R1.3 and R3.7. The SAR does not refer to retirement of FAC-011-3 R1.3 and R3.7 nor retirement of the IROL definition in the NERC glossary. Therefore it is not necessary nor efficient to replace "IROL(s)" with its definition in the CIP-002 criteria 2.6 and 2.9.	
Likes	0
Dislikes	0

Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
It is not necessary to change CIP-002 with the retirement of FAC-010. Identifying IROLs is still required in FAC-011-3 R1.3 and R3.7. The SAR does not refer to retirement of FAC-011-3 R1.3 and R3.7 nor retirement of the IROL definition in the NERC glossary. Therefore it is not necessary nor efficient to replace "IROL(s)" with its definition in the CIP-002 criteria 2.6 and 2.9.	
Likes	0
Dislikes	0

Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Reclamation recommends simplifying the Impact Rating Criteria using the methodology described below.	

BES Cyber Systems are to be rated as high, medium, or low impact as follows:

1. A high impact BES Cyber System has one or more of the following characteristics:

- 1.1 Is used to operate transmission lines of 500kV or above
- 1.2 Supports a sum greater than 2500kV of transmission lines above 230kV
- 1.3 Supports generation with an aggregate capacity greater than 3000MW
- 1.4 Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact

2. A medium impact BES Cyber System has one or more of the following characteristics:

- 2.1 Supports generation with the aggregate capacity between 1500 – 3000MW
- 2.2 Supports a sum between 1500 – 2500kV of transmission lines above 230kV
- 2.3 Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more

3. A low impact BES Cyber System has one or more of the following characteristics:

- 3.1 Supports a sum less than 1500kV of transmission lines above 230kV
- 3.2 Supports transmission only between 110 – 230kV
- 3.3 Supports generation with an aggregate capacity between 75 – 1500MW
- 3.4 Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System
- 3.5 Supports any Facilities that are designated a blackstart resource
- 3.6 Supports any other RAS not already identified as a medium impact BES Cyber System

Likes 0

Dislikes 0

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer

No

Document Name

Comment

First, City Light appreciates the efforts made by the drafting teams for NERC projects 2015-09 and 2016-02 to align work such that CIP-002-5.1 is revised only by one drafting team. The proposed SAR achieves this specific goal, but does not address the larger objective of consistency of effort. The

issue in that the same language about IROLs that is part of CIP-002 also is incorporated in CIP-014-2 (see Section 4.1.1.3). To ensure consistency, the IROL replacement language in both CIP-002 and CIP-014 should be handled by the same drafting team. The existing SAR for project 2016-02 does not include CIP-014 in its scope. As a result, it may be best to leave the IROL replacement language work for CIP-002 within project 2015-09, to ensure consistency between CIP-002 and CIP-014.

Second, City Light is concerned that the IROL replacement language proposed in the IROL SAR does not represent an administrative replacement of more-or-less equivalent terms, but rather has a different meaning that introduces potential for expanded scope and unintended consequences. Expanded scope because under the language as proposed, any contingency studied in a Planning Assessment that shows BES Cascading, Uncontrolled Separation, or Instability—even if the contingency is an extra-extreme case, well beyond anything considered in the traditional study of IROLs, a case examined only for exploratory purposes—thus triggers inclusion of associated Elements within scope for CIP protections. Unintended consequences because as different extra-extreme cases are studied in successive years, Elements may go in and out of scope for CIP protections on an annual basis. Unintended consequences also because to avoid these situations, Planners may choose to limit their Planning Assessments only to those contingencies required by the applicable Planning Standards and thus limit the study of grid behavior under unusual, unexpected cases. As such, City Light recommends that the proposed IROL replacement language be struck from the SAR. This change will allow the applicable drafting team, whichever it is, full flexibility to address the IROL replacement language. A reference to the proposed language might be included in the SAR, but in terms of one possible approach and not as the presumptive solution.

Thank you for your consideration.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy is concerned with the process implications that could occur by going forward with the FAC SDT's recommendations to CIP-002 at this time. Potential exists for industry confusion if one project gets ahead of the other. For example, what if the FAC project is stalled, or never fully approved by FERC? The revisions being proposed in CIP-002 then would no longer be acceptable. Going ahead with implementing the revisions suggested by another Project SDT while that Project has not been approved, and is still in active development is premature. We suggest that any revisions be put on hold until after the FAC project has been approved by FERC.

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 1,3,5,6

Answer

No

Document Name

Comment

While APS agrees with the need to modify Criteria 2.6 and 2.9 and understands the goal of efficiency this SAR is intended to achieve, APS has significant concerns regarding the consolidation of the IROL-related efforts into a CIP-focused drafting team. The criteria set forth at 2.6 and 2.9 are inherently technical and require engineering and operational expertise beyond the information technology aspects of the majority of CIP-002. More specifically, because these criteria will be premised upon the processes, assessments, and deliverables resulting from engineering analyses, APS respectfully asserts that the value the SDT is intending to recognize through the proposed transfer and consolidation is outweighed by the potential drawbacks that will result from the loss of engineering and operational expertise represented on the previous 2015-09 SDT.

Likes 0

Dislikes 0

Response

John Allen - City Utilities of Springfield, Missouri - 1,3,4

Answer

No

Document Name

Comment

While I do agree with the need to revise criterion 2.6 and 2.9 in Attachment 1 of CIP-002, I am concerned the language proposed by the SOL SDT may not be sufficiently clear (a "bright line") to prevent varying interpretations of what indicates System instability, Cascading and/or uncontrolled separation and thus properly identifying Medium Impact BES Cyber Systems. The Planning Assessments for TPL-001 include many different Contingency events that may indicate some level of System instability, Cascading and/or uncontrolled separation. However, they may not justify a medium impact rating for the associated BES Cyber Systems. Therefore, I suggest keeping the IROL designation and relying on the RC and its methodology for identification. See comments from FMPA for a possible solution.

Likes 0

Dislikes 0

Response

Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer

No

Document Name

Comment

FMPA appreciates the SDTs efforts with Project 2016-02 and CIP-002. We disagree with the changes being proposed for sections 2.6 and 2.9 of Attachment 1. We propose the following language for 2.6:

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

FAC-011-3 applies to the Reliability Coordinator (RC) and requires the RC to have a documented methodology for developing SOLs and specifically (R1.3) the subset of SOLs that are IROLs. In this way the language "as critical to the derivation of Interconnection Reliability Operating Limits (IROLs)

and their associated contingencies” can be left in the standard instead of replaced as the SDT proposes. The replacement language proposed by the SDT is not clear and could possibly bring Facilities that are currently and appropriately out of scope, into scope. For example, what does “an element of each Contingency event” mean? Would it apply if it were an element of only one event, or does it have to be an element of each event studied? We recommend our proposed language above.

We see no reason to change the language for Section 2.9. The issues raised in the SAR do not point to a necessity to change Section 2.9.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion

Answer

No

Document Name

Comment

For 2.6

- 1) Recommend that there be a Requirement for the Planning Coordinator / Transmission Planner to notify the TOP/TO/GOP/GO that their location has been so designated.
- 2) Recommend changing “identified” to “notified”.

For 2.9

Request clarification on how the TOP/TO/GOP/GO knows their RAS has been so designated. Does PRC-012-2 help clarify?

We recommend that the proposed criteria language be removed from the SAR to provide the SDT maximum flexibility.

We recommend that associated Guideline and Technical Basis “Technical Rationale” criterion information should be revised accordingly for changes made to the Impact Rating Criteria.

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECl

Answer

Yes

Document Name	
Comment	
The SDT should review all SOL/IROL related standards and evaluate if all references to IROLs should be removed with regards to applicability and requirements specific to the planning horizon.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports the proposed CIP-002-5.1a SAR because it provides sufficient scope and direction for the SDT to implement changes to CIP-002 required by retiring FAC-010-3.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment

Electric Reliability Council of Texas, Inc. encourages coordination between the standards drafting teams for Projects 2015-09 and 2016-02 in order to ensure revisions achieve their intended purpose.

Likes 0

Dislikes 0

Response**Russell Martin II - Salt River Project - 1,3,5,6 - WECC**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Douglas Johnson - American Transmission Company, LLC - 1**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Warren Cross - ACES Power Marketing - 2,4,5,6 - WECC,Texas RE,SERC,RF, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standards? If yes, please identify the jurisdiction and specific regulatory requirements.

Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer No

Document Name

Comment

None that we are aware of.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer No

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer No

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 2,4,5,6 - WECC,Texas RE,SERC,RF, Group Name ACES Standards Collaborators

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

John Allen - City Utilities of Springfield, Missouri - 1,3,4

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes	0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI

Answer No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

3. Are there any other concerns with this SAR that haven't been covered in previous questions?

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer No

Document Name

Comment

See Question 1 comments

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer No

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion

Answer No

Document Name

Comment

We recommend that the Guidelines and Technical Basis "Technical Rationale" for Criterion 2.3 be revised to reference TPL-001-4, instead of TPL-003.

Likes 0

Dislikes 0

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6**Answer** No**Document Name****Comment**

Likes 0

Dislikes 0

Response**Thomas Foltz - AEP - 3,5****Answer** No**Document Name****Comment**

Likes 0

Dislikes 0

Response**Marty Hostler - Northern California Power Agency - 5,6****Answer** No**Document Name****Comment**

Likes 0

Dislikes 0

Response**Dennis Sismaet - Northern California Power Agency - 5,6****Answer** No**Document Name****Comment**

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 1,3,4, Group Name FirstEnergy Corporation

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

John Allen - City Utilities of Springfield, Missouri - 1,3,4

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Warren Cross - ACES Power Marketing - 2,4,5,6 - WECC,Texas RE,SERC,RF, Group Name ACES Standards Collaborators

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer

No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
<p>Is the modified language in 2.6 correct? For example, an entity performs a Planning Assessment and has 20 contingency events that result in System instability, Cascading, or uncontrolled separation. Generator X is an element in 19 of those 20 contingency events. From the modified language in 2.6, the BES Cyber Systems associated with generator X would not have a medium impact rating in accordance with 2.6 because generator X was not an element of each of the 20 contingency events. Is this the intent of this language?</p>	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
<p>Reclamation recommends that impact ratings apply to all BES Cyber Systems regardless of a Responsible Entity's functional registration (Transmission or generation).</p> <p>Reclamation also recommends that if the SDT modifies the Control Center definition, at least one member with CIP expertise and at least one member with O&P expertise should be on the team.</p>	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Duke Energy is unclear on the language, and the necessity of bringing the Elements in as they are proposed in this standard. First, the terms System instability, Cascading, or uncontrolled separation may be interpreted differently depending on the PC/TP. The proposed criteria introduce a level of subjectivity that was intentionally eliminated from Version 5. Second, the term "Planning Assessment" is used which includes evaluation of Extreme Events under TPL-001. Providing a Medium impact classification to Facilities that are only identified during an Extreme Event is inappropriate. Third, with respect to generation, criterion 2.3 currently addresses a generation Facility that has been designated to avoid an Adverse Reliability Impact. The proposed criterion 2.6 is potentially duplicative with respect to generation. Fourth and most importantly, TP/PC identified SOLs/IROLs are proposed to be removed from the FAC standards. We are unclear why identification would be unnecessary in FAC-010, but those same Facilities that would have been identified are important enough to be labeled as Medium impact in this CIP standard.

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 1,3,5,6

Answer Yes

Document Name

Comment

APS has interpreted the intent of the SAR to be a simple transference of the proposed language drafted by the Project 2015-09 STD to the Project 2016-02, to incorporate into Draft 3 of CIP-002-6 thereby consolidating the drafting and comment processes. APS is concerned that this consolidation could adversely impact the iterative comment and balloting process that normally accompanies the standards drafting process. Further, and importantly, the scope, objectives, and context around the drafting of these revisions have been shifting throughout the course of these SDTs' efforts. For this reason, APS recommends that the SAR be modified to indicate that the commenting periods shall occur as necessary based on the comments and feedback received from industry. As currently written, it appears that the SAR contemplates only one comment period, which APS believes is likely inadequate to re-calibrate the revisions and industry input.

APS is not in agreement with the proposed modifications to Criteria 2.6 as written by the Project 2025-09 STD. Not all events that result in system instability, cascading, or controlled separation would result in an IROL. This could pull in "extreme events" as defined in TPL-001-4, which is too broad. APS proposes the following language for Criterion 2.6 in order to clarify that it is not applicable to Extreme Events that are also studied within the Planning Assessment:

2.6 Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner as an element of each P0 – P7 Contingency event included in the Planning Assessment that result in System instability, Cascading or uncontrolled separation.

Likes 0

Dislikes 0

Response

Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer Yes

Document Name

Comment

Is transferring the SAR the same as subdividing it? From the Standards Process Manual: “ ***If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.***” My concern is does transferring the SAR from one Project to another stay within the process outlined in the Standards Process Manual? FMPA appreciates the challenge the SDTs have of incorporating changes made to other families of standard requirements with the CIP requirements.

Likes 0

Dislikes 0

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer Yes

Document Name

Comment

The SPP Standards Review Group (“SSRG”) offers that the language proposed by Project 2015-09 SDT could be interpreted as overly broad, and could expand the list of facilities that would be identified as Medium Impact BES Cyber Systems. The SSRG recommends that the Standard Drafting Team exclude contingent elements that are classified as Extreme Events from consideration for Criterion 2.6. If Extreme Events from the Planning Assessment are included in Criterion 2.6, the list of identified facilities could grow to include facilities that would otherwise be Low Impact BES Cyber Systems. This could create confusion amongst the industry how to account for those assets. The SSRG has included proposed language for your consideration (shown as a blackline against the draft proposal):

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner as a **contingent** element of Planning event (**P1-P7**) included in the Planning Assessment that result in System instability, **for conditions such as Cascading, voltage instability, or uncontrolled islanding and cannot be adequately mitigated with a Corrective Action Plan or System adjustment.**

2.9. Each **Special Protection System (SPS)**, Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in System instability, **for conditions such as Cascading, voltage instability, or uncontrolled islanding and cannot be adequately mitigated with a Corrective Action Plan or System adjustment.**

Likes 0

Dislikes 0

Response

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This will be the first draft adding the IROL removal language due to the retirement of the FAC-010 Reliability Standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
Standards Committee approved SAR for posting – IROL Modifications	August 22, 2018
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with initial ballot	August 22 – October 1, 2018

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 11 – December 17, 2018
10-day final ballot	January 25 – February 5, 2018
NERC Board	February 6, 2018

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See implementation plan for CIP-002-6.

5.1 Planned and Unplanned Changes: If a Responsible Entity has a Planned Change¹ or Unplanned Change,² the Responsible Entity shall comply with the requirements in this Reliability Standard as follows: For Planned Changes resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard upon the commissioned date of the Planned Change. For this provision, the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES. For requirements that contain periodic obligations, initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.

For Unplanned Changes resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below. As used in the table, the phrase “BES asset type” refers to the following BES asset types listed in Requirement R1 of CIP-002: (i) Control Centers or backup Control Centers; (ii) Transmission stations or

¹ **Planned Changes** are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity’s advance knowledge. Planned Changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen by the Responsible Entity. Examples of Planned Changes include, but are not limited to: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² **Unplanned Changes** refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity’s advance knowledge or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of Unplanned Changes include, but are not limited to: (1) a Responsible Entity is notified (internally or externally) that a generation Facility has been designated per CIP-002, Attachment 1, Criterion 2.3; (2) a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per CIP-002, Attachment 1, Criterion 2.6; (3) a generating resource that is connected at less than 100kV is designated per CIP-002, Attachment 1, Criterion 3.4; or (4) a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in CIP-002, Attachment 1, Criterion 2.10.

substations; (iii) generation resources; (iv) systems and facilities critical to system restoration including Blackstart Resources and Cranking Paths and initial switching requirements; (v) Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and (vi) the Distribution Provider Protection Systems specified in Applicability section 4.2.1.

Scenario of Unplanned Change	Implementation Period
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above, with the following exception: the Responsible Entity shall initially perform Part 2.2 of Requirement R2 by the date the Implementation Period ends where the Unplanned Change results in a high or medium impact BES Cyber System and the Responsible Entity previously had neither a high nor a medium impact BES Cyber System.

For Unplanned Changes resulting in a higher categorization for an existing BES Cyber System, the Responsible Entity shall continue to comply with the applicable requirements of the prior categorization during the Implementation Period defined in the table above.

6. **Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

BES Cyber Systems The term “BES Cyber System” is to provides a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is real-time scoping. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than “Real-time,” the following definition applies: BES Cyber Assets are those Cyber Assets that, if

rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not consider the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria provided in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.13 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent instability, Cascading, or uncontrolled separation.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry’s overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

- 2.12.** Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO, GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO, TOP, GO, GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real-time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real-time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions, and conditions which ensure, in real-time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO, DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP, TO, DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO, DP)

Managing Constraints

Managing Constraints includes activities, actions, and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor System Operating Limits (SOLs) & Interconnection Reliability Operating Limit (IROL) (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions, and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions, and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situational Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC, BA)
- Change management (TOP, GOP, RC, BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)

- Frequency monitoring (BA, RC)

Inter-Entity Coordination and Communication

The Inter-Entity Coordination and Communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these CIP Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.13 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities.

However, in a substation that includes equipment that supports BES operations along with equipment that only supports distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3, and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of

BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002-1, whose purpose was "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it required that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various BAs in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is

necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified in a Planning Assessment of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena such as instability or voltage collapse. Identification of these instances and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 designates those BES Cyber Systems in Remedial Action Schemes (RAS) installed to ensure reliable BES operation as medium impact. The degradation, misuse, or unavailability of these BES Cyber Systems could potentially result in Wide Area impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been

included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in instability, Cascading, or uncontrolled separation. Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500 kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to

three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 includes BES Cyber Systems for those Transmission Facilities that have been identified in a Planning Assessment of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates those BES Cyber Systems in Remedial Action Schemes (RAS) installed to ensure reliable BES operation as medium impact. The degradation, misuse, or unavailability of these BES Cyber Systems could potentially result in Wide Area impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed.
- Criterion 2.10 designates those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more as medium impact. The SDT discussed the wording of Criterion 2.10, and chose the term "Each" to show that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team included only those Systems that did not require human operator initiation, and targeted those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be

subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. Those qualifying systems which require a human operator to arm the system and subsequently trigger automatically, are still considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards for the preceding 12 months to account for seasonal fluctuations.

The 300 MW threshold was provided in Version 1 of the CIP Reliability Standards. The SDT believes that the threshold should be lower than the 1500 MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs are not part of the NERC or regional reliability Load shedding programs. They are offered as components of an ancillary services market and do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that define the required level of impact to the BES and an associated risk threshold to establish a floor for applicable medium impact BES Cyber Systems.

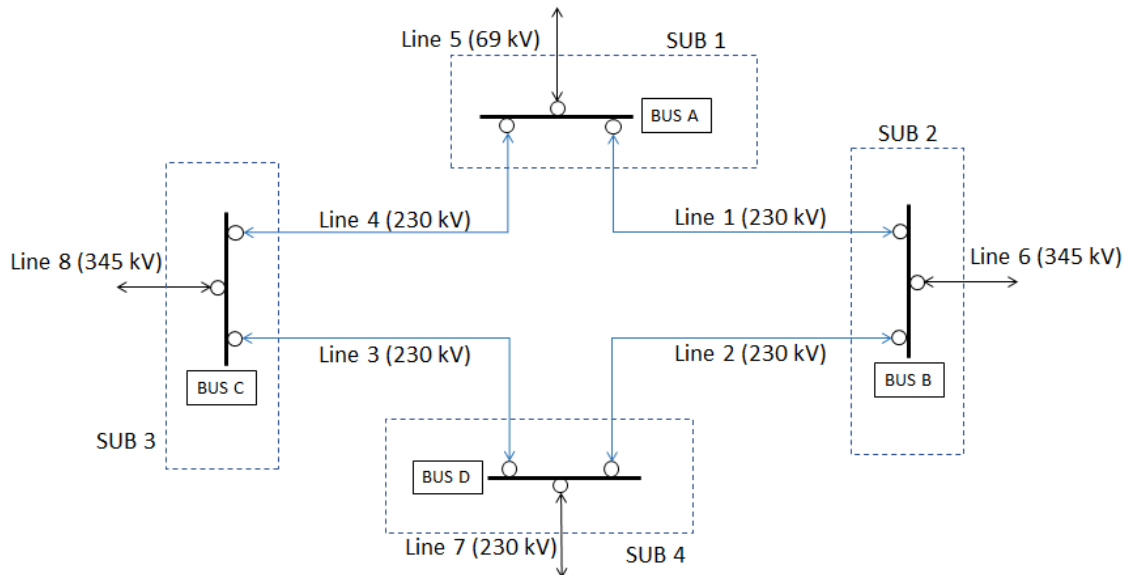
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at a level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below

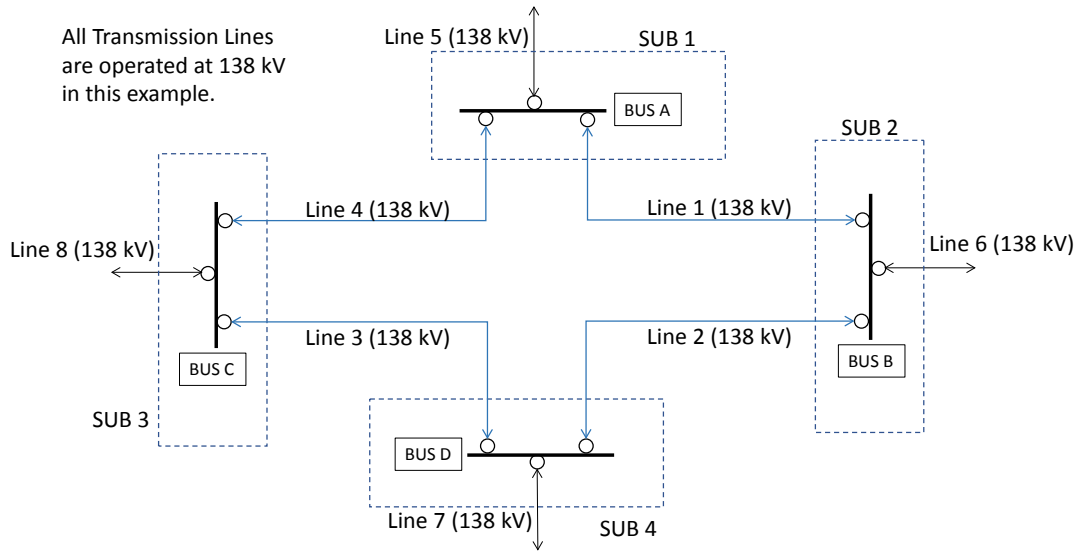
and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

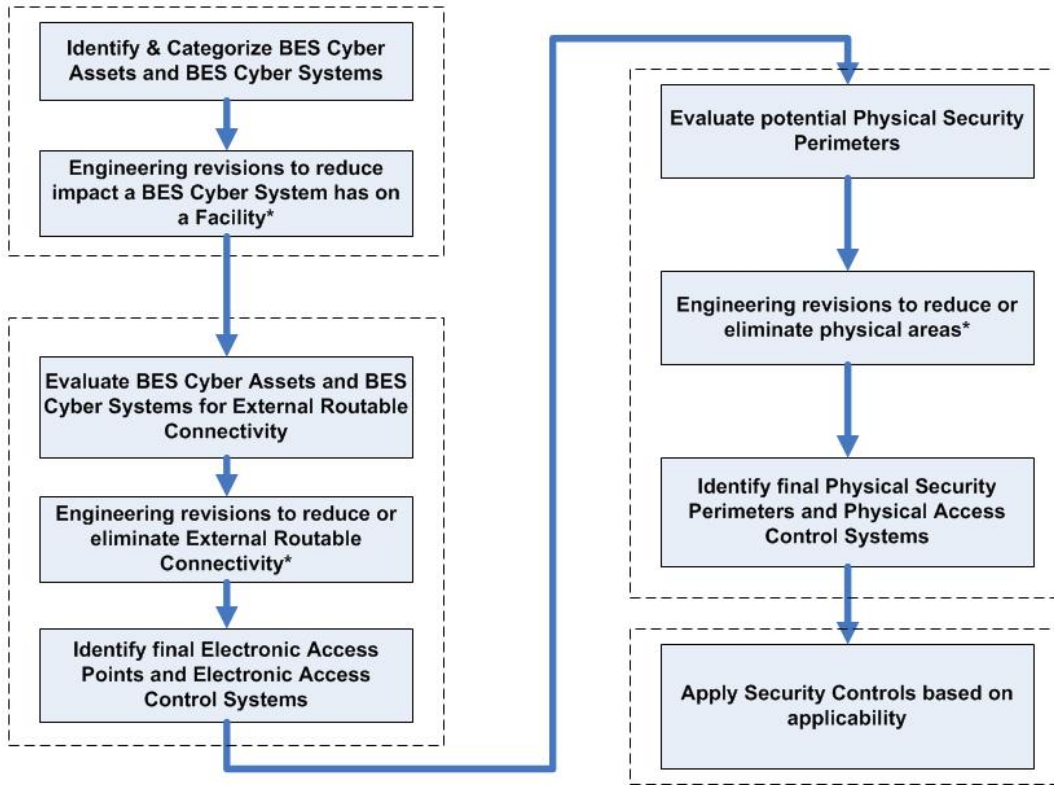
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a Generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

~~This is the third draft of the proposed standard. This will be the first draft adding the IROL removal language due to the retirement of the FAC-010 Reliability Standard.~~

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
Standards Committee approved SAR for posting – IROL Modifications	August 22, 2018
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with initial ballot	August 22 – October 1, 2018

Anticipated Actions	Date
45-day formal comment period with additional ballot	May 18 – July 2, 2018 <u>November 11 – December 17, 2018</u>
10-day final ballot	July 30 – August 8, 2018 <u>January 25 – February 5, 2018</u>

NERC Board	August 16 <u>February</u> <u>6</u> , 2018
------------	---

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** 5.1 See implementation plan for CIP-002-6.

5.21 Planned and Unplanned Changes: If a Responsible Entity has a Planned Change¹ or Unplanned Change,² the Responsible Entity shall comply with the requirements in this Reliability Standard as follows: in accordance with the following:

For Planned Changes resulting in a new BES Cyber System or a change in categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard upon the commissioned date of the Planned Change. For this provision, the commissioned date is the date a new or modified Bulk Electric System asset or Cyber Asset is capable of impacting the BES. For requirements that contain periodic obligations, initial performance of those obligations following a Planned Change shall occur within the first period following the commissioned date of the Planned Change.

For Unplanned Changes, resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the Responsible Entity shall comply with all newly applicable requirements in this Reliability Standard according to the timelines in the table below. As used in the table, the phrase “BES

¹ Planned Changes refer to are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity’s advance knowledge awareness. Planned Changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen that was foreseen by the Responsible Entity. Examples of Planned Changes include, but are not limited to: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² Unplanned Changes refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity’s advance knowledge awareness or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of Unplanned Changes include, but are not limited to: (1) when a Responsible Entity is notified (internally or externally) that a generation Facility has been designated as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year per (CIP-002, Attachment 1, Criterion 2.3); (2) when a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per as critical to the derivation of an IROL and their associated contingencies (CIP-002, Attachment 1, Criterion 2.6); (3) when a generating resource that is connected at less than 100kV is designated as a new Blackstart Resource along with its Cranking Path per (CIP-002, Attachment 1, Criterion 3.4); or (4) when a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in CIP-002, Attachment 1, Criterion Criterion-2.10 of CIP-002, Attachment 1.

asset type” refers to the following BES asset types listed in Requirement R1 of CIP-002: (i) Control Centers or backup Control Centers; (ii) Transmission stations or substations; (iii) generation resources; (iv) systems and facilities critical to system restoration including Blackstart Resources and Cranking Paths and initial switching requirements; (v) Remedial Action Schemes ~~Special Protection Systems~~ that support the reliable operation of the Bulk Electric System; and (vi) the Distribution Provider Protection Systems specified in Applicability section 4.2.1.

Scenario of Unplanned Change	Implementation Period
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New high impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	12 calendar months from the date of notification or detection of the Unplanned Change.
New low impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type	24 calendar months from the date of notification or detection of the Unplanned Change.

For requirements that contain periodic obligations, initial performance of those obligations following an Unplanned Change shall occur within the first period following the date that the Implementation Period ends, as defined in the table above, with the following exception: except that the Responsible Entity shall initially perform Part 2.2 of Requirement R2 by the date the Implementation Period ends where the Unplanned Change results in a high or medium impact BES Cyber System and the Responsible Entity previously had neither a high nor a medium impact BES Cyber System.

For Unplanned Changes resulting in a higher categorization for an existing BES Cyber System, the Responsible Entity shall continue to comply with the applicable requirements of the prior categorization during the Implementation Period defined [in the table](#) above.

- 6. Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

BES Cyber Systems The term “BES Cyber System” is to provides a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is ~~a real-time scoping characteristic~~. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the ~~application of these~~ CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than “Real-time,” the following definition applies: BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not ~~consider~~include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria ~~provided~~defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.13 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** – Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location ~~that are~~ identified by ~~the~~its Reliability Coordinator, Planning Coordinator, or Transmission Planner, per its Planning Assessments of the Near-Term Transmission Planning Horizon or the Planning Coordinator's -Transfer Capability Assessment (Planning Coordinator only), as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separations as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would instability, Cascading, or uncontrolled separation cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a

~~reduction in one or more IROs if destroyed, degraded, misused, or otherwise rendered unavailable.~~

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry's overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center's associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center's associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

2.12. Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,_GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,_GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (~~real~~real-time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,_DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in ~~real~~real-time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions, and conditions which ensure, in ~~real~~real-time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO, DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP, TO, DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO, DP)

Managing Constraints

Managing Constraints includes activities, actions, and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor System Operating Limits (SOLs) & Interconnection Reliability Operating Limit (IROL)s (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions, and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions, and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situational Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC, BA)
- Change management (TOP, GOP, RC, BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)

- Frequency monitoring (BA, RC)

Inter-Entity Coordination and Communication

The Inter-Entity ~~coordination~~-Coordination and ~~communication~~-Communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these ~~Version 5 Cyber Security~~CIP Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.13 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For

example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports ~~Distribution~~ distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3, and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, ~~Bas~~BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002-1, whose purpose ~~is-was~~ "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it ~~requireds~~ that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various ~~BAas~~ in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified

as a result of a “long term” reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified in a Planning Assessments of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of IROLs and their associated contingencies, as specified by FAC 014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.

Instances of instability, Cascading, or uncontrolled separation IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Identification of these instances Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes designates those BES Cyber Systems for in Remedial Action Schemes (RAS) may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact. installed to ensure reliable BES operation as medium impact. The degradation, misuse, or unavailability of these BES Cyber Systems could potentially result in Wide Area

impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in instability, Cascading, or uncontrolled separation exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500_kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "~~Integrated Risk Assessment Approach – Refinement to Severity Risk Index~~Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 includes BES Cyber Systems for those Transmission Facilities that have been identified in a Planning Assessment of the Near-Term Transmission Planning Horizon or a Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of IROs and their associated contingencies, as specified by FAC 014 2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation

owner as to the qualification of generation Facilities connected to their Transmission systems.

- Criterion 2.9 designates ~~as medium impact~~ those BES Cyber Systems, ~~for those in~~ Remedial Action Schemes (RAS) ~~or automated switching Systems,~~ installed to ensure reliable BES operation as medium impact ~~within IROLs.~~ The degradation, ~~compromisemisuse,~~ or unavailability of these BES Cyber Systems could potentially ~~would~~ result in exceeding IROLs Wide Area impacts such as instability, Cascading or uncontrolled separation if they fail to operate as designed. ~~By the definition of IROL, the loss or compromise of any of these have~~ Wide Area impacts.
- Criterion 2.10 designates ~~as medium impact~~ those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more as medium impact. The SDT ~~spent considerable time discuss~~ed the wording of Criterion 2.10, and chose the term “Each” to ~~show~~represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team ~~sought to~~ included only those Systems that did not require human operator initiation, and targeted ~~in~~ particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. ~~It should be noted that~~ those qualifying systems which require a human operator to arm the system and subsequently, but once armed, trigger automatically, are still ~~to be~~ considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, ~~for the preceding 12 months to account for seasonal fluctuations.~~

~~The is particular threshold (300 MW),~~ threshold was provided in ~~CIP,~~ Version 1 of the CIP Reliability Standards. The SDT believes that the threshold should be lower than the 1500 MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs ~~that~~ are not part of the NERC or regional reliability Load shedding programs. ~~They, but~~ are offered as components of an ancillary services market and do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that ~~define would ensure~~ the required level of impact to the BES ~~is defined~~ and ~~an associated~~ a risk threshold ~~associated~~ to establish a floor for applicable medium impact BES Cyber Systems.

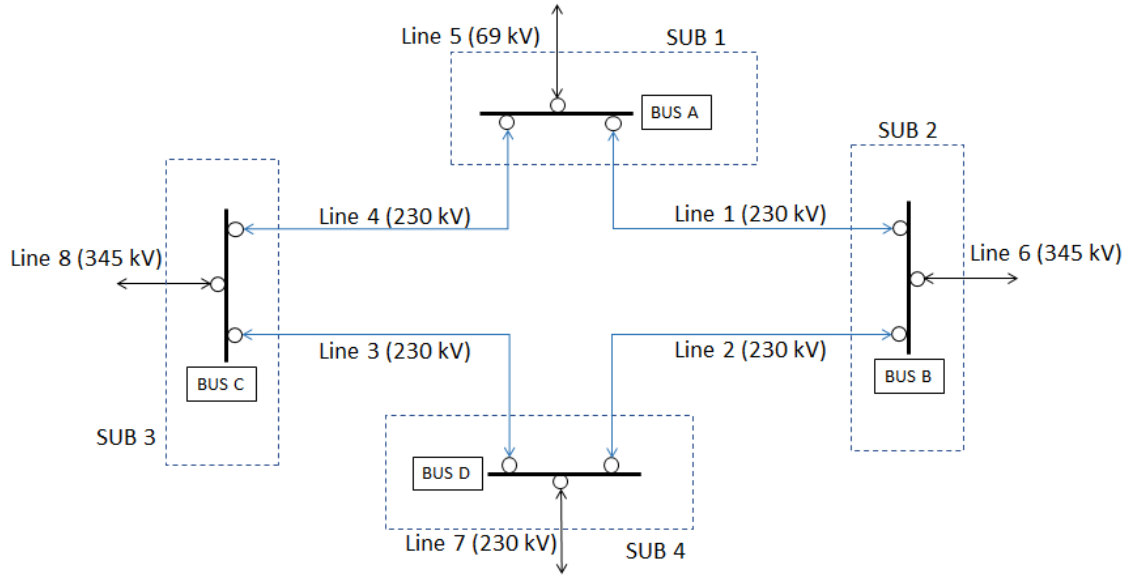
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at ~~an appropriate~~ level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

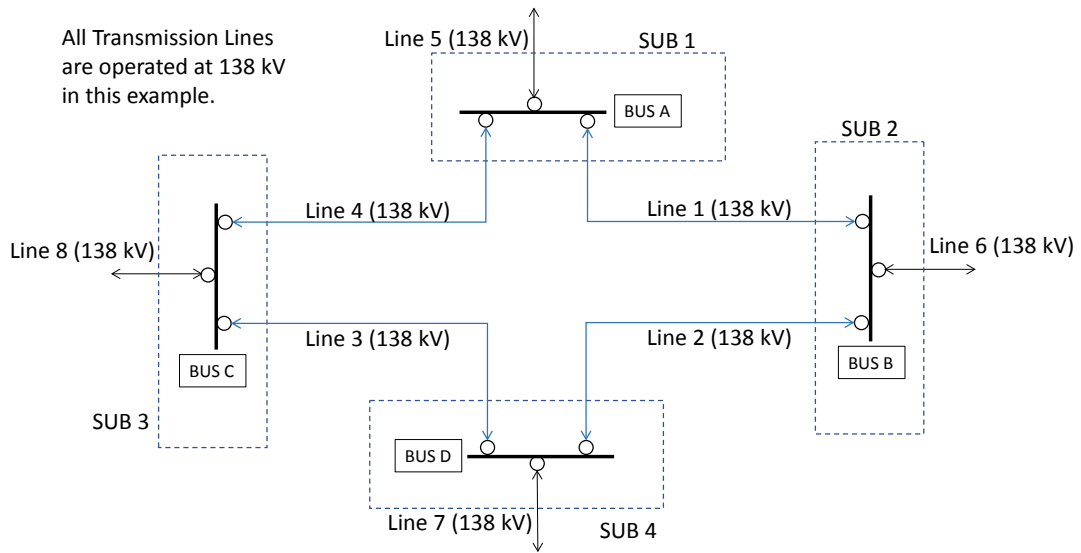
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A

100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration

assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

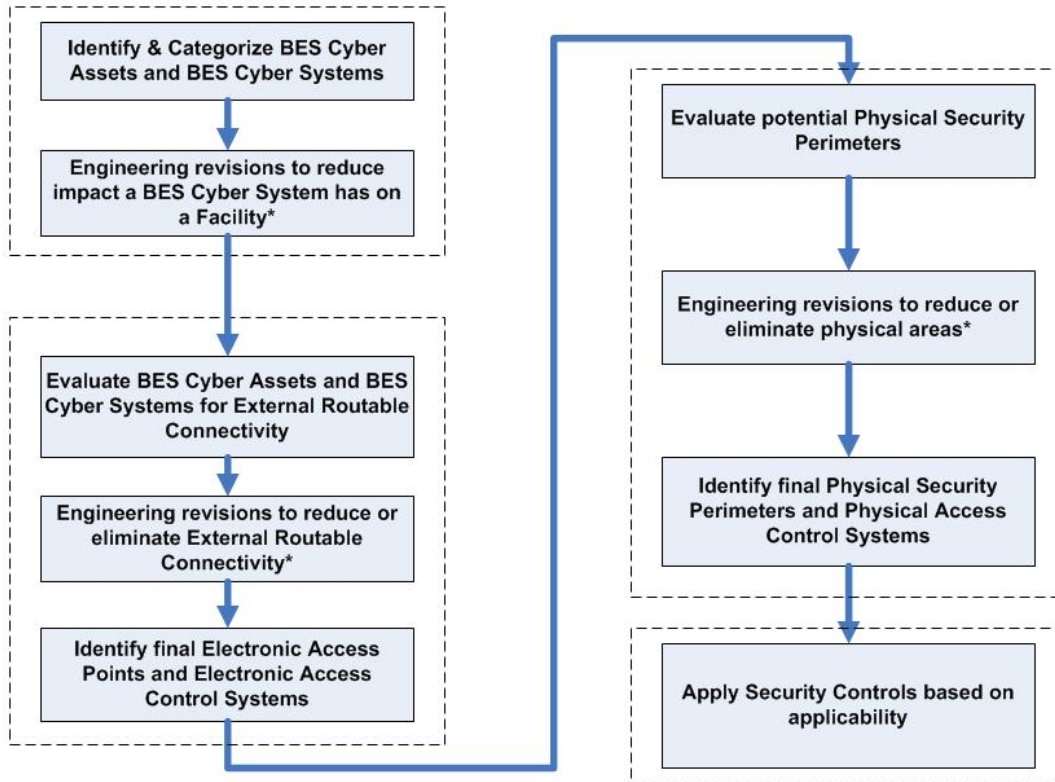
Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a ~~generator~~ Generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber

Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is fifteen (15) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is ~~three-fifteen~~ (315) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective on the first day of the first calendar quarter that is ~~three-fifteen~~ (315) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

~~For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber Security Standards.~~

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards

CIP-002-6

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System](#) to submit comments on **CIP-002-6 - Cyber Security – BES Cyber System Categorization (Transmission Owner Control Center performing Transmission Operator obligations)**. Comments must be submitted by **8 p.m. Eastern, Tuesday, October 9, 2018**.

Additional information is available on the [project page](#). If you have questions, contact Standards Developer, [Jordan Mallory](#) (via email) or at 404-446-2589.

Background Information

Project 2016-02 (1) addresses the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822 and (2) considers the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document).

The V5TAG, which consisted of representatives from NERC, Regional Entities and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP Version 5 standards and to support industry's implementation activities. During the V5TAG's activities, it identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the [CIP Version 5 Transition Advisory Group Issues for Consideration](#) document to formally recommend that the SDT address these issues and consider modifications to the standard language during the standards development process. Among other issues of the V5TAG recommended clarification of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12. The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a Transmission Owner Control Center that performs the functional obligations of a Transmission Operator.

The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12. The aggregate weighted value is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the BES Cyber System(s) exceeds the 6000 aggregate weighted value, it should be identified as a medium impact BES Cyber System. If the BES Cyber System does not exceed the 6000 aggregate weighted value, it should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

Reliability Standard CIP-002-5.1a (Impact Rating Criterion 2.6 in Attachment 1), however, references IROLs identified by Planning Coordinators and Transmission Planners. The Project 2015-09 SDT concluded that there is a need to modify CIP-002-5.1a to account for the retirement of FAC-010-3 and the elimination of a requirement for planners to identify SOLs and IROLs. The Project 2015-09 SDT developed draft language to replace the reference to such IROLs in Criterion 2.6 with other language that would allow Planning Coordinators and Transmission Planners to identify Facilities that otherwise do not meet the criteria in Section 2 of Attachment 1 but pose a higher risk to reliability such that its BES Cyber Systems should be protected as Medium Impact. In addition, the Project 2015-09 SDT recommends revising the IROLs reference in Impact Rating Criterion 2.9 in Attachment 1 to CIP-002-5.1a. reference in Impact Rating Criterion 2.9 in Attachment 1 to CIP-002-5.1a.

Questions

1. Attachment 1, Criterion 2.6: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6? If not, please provide your rationale and an alternate proposal.

Yes
 No

Comments:

2. Attachment 1, Criterion 2.9: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.9? If not, please provide your rationale and an alternate proposal.

Yes
 No

Comments:

3. Attachment 1, Criterion 2.12: No changes have been added from the previous ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Yes
 No

Comments:

4. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

Yes
 No

Comments:

5. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

- Yes
 No

Comments:

6. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

- Yes
 No

Comments:

7. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

- Yes
 No

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	Medium
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity’s CIP management program.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The VRF is not being modified for this requirement. The modification is a clarification of Criteria 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity’s CIP management program. The modification is a clarification of Criteria 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1

Proposed VRF	Medium
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1

Lower	Moderate	High	Severe
<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high or</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</p>

<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber</p>	<p>have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
---	--	---	---

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	
--	---	---	--

VSL Justifications for CIP-002-6 Requirements R1

<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criteria 2.6, 2.9, and 2.12 of Attachment 1 to CIP-002-6.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.</p>

<p>FERC VSL G4</p> <p>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.</p>
--	--

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through **October 9, 2018**

Ballot Pools Forming through **September 21, 2018**

[Now Available](#)

A 45-day formal comment period for **C CIP-002-6 - Cyber Security – BES Cyber System Categorization** and **CIP-003-8 - Cyber Security – Security Management Controls** is open through **8 p.m. Eastern, Tuesday, October 9, 2018**.

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience difficulty using the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, September 21, 2018**. Registered Ballot Body members can join the ballot pools [here](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 28 – October 9, 2018**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards | CIP-002-6
Comment Period Start Date: 8/23/2018
Comment Period End Date: 10/9/2018
Associated Ballots: 2016-02 Modifications to CIP Standards CIP-002-6 Draft 1 IN 1 ST

There were 61 sets of responses, including comments from approximately 150 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. **Attachment 1, Criterion 2.6:** Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6? If not, please provide your rationale and an alternate proposal.

2. **Attachment 1, Criterion 2.9:** Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.9? If not, please provide your rationale and an alternate proposal.

3. **Attachment 1, Criterion 2.12:** No changes have been added from the previous ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

4. **Guidelines and Technical Basis:** Do you agree with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

5. **Guidelines and Technical Basis:** Do you agree with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

6. **Implementation Plan:** The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

7. **The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
					Troy Lee	Santee Cooper	1,3,5,6	SERC
					Jennifer Richards	Santee Cooper	1,3,5,6	SERC
					Chris Jimenez	Santee Cooper	1,3,5,6	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Lincoln Electric System	Eric Ruskamp	6		LES	Eric Ruskamp	Lincoln Electric System	6	MRO
					Dan Pudenz	Lincoln Electric System	1	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Joseph Smith	Prairie Power	3	SERC

					Susan Sosbe	Wabash Valley Power Association	3	RF
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
FirstEnergy - FirstEnergy Corporation	Julie Severino	1		FirstEnergy	Aubrey Short	FirstEnergy - FirstEnergy Corporation	4	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and HQ	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC

					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC

Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
Ted Hilmes	KAMO Electric Cooperative	3	SERC
Walter Kenyon	KAMO Electric Cooperative	1	SERC
Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Attachment 1, Criterion 2.6: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6? If not, please provide your rationale and an alternate proposal.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

The undefined term 'instability' could expand the scope of both medium and high impact cyber asset classification. Potentially, every BES generator and every BES Transmission Cyber Asset would meet the medium impact criteria. Generators with a Control Center at the facility could be classified as high impact Cyber Assets, whether or not an IROL was impacted. With the requirement not having any minimum threshold for generator BCSs, the criteria could be interpreted to apply to any BES generator.

Dominion Energy recommends that the term 'instability' be eliminated from any of the Requirements and Attachments in CIP-002-6.

If the SDT chooses to leave the term 'instability' in CIP-002-6, Dominion Energy recommends that this term be limited to Wide Area impacts, as outlined in the Guidelines and Technical Basis document for criteria 2.9 of Appendix 1. This would be consistent with the scope of CIP-014 that limits the scope to instability within an Interconnection.

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer No

Document Name

Comment

AEP does not believe the proposed draft language in Criterion 2.6 properly address the issue of notification. A Responsible Entity would have no way of knowing the results of these studies unless the PC and/or TP functions are performed internally. AEP understands that a requirement for the TP or PC to communicate this status to Responsible Entities, primarily GOs and TOs, has been proposed for FAC-015-1, R4. The language in Criterion 2.6 should incorporate words that indicate the source Entity is the TP or PC. In addition, AEP is not convinced that the RC should be removed from this Criterion. With these ideas in mind, AEP suggests the SDT consider the language for Attachment Criterion 2.6 that follows:

*"Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator, Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation when **notified by the Reliability Coordinator, Transmission Planner, or Planning Coordinator.**"*

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer No

Document Name

Comment

The NSRF proposes the following new wording for Criterion 2.6. which is similar to the present wording, "Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies".

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0

Dislikes 0

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer No

Document Name

Comment

LES supports the following NSRF comments:

The NSRF proposes the following wording for Criterion 2.6. which is similar to the present wording, "Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies".

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer

No

Document Name

Comment

AZPS is not in agreement with the proposed modifications to CIP-002-6 Attachment 1, Criterion 2.6. There are several reasons for AZPS's disagreement. The first is that, in reviewing this language, AZPS interprets the proposed modification as resulting in a change to the previous language and the underlying obligation - not simply a movement or revision of language as proposed in the SAR. More specifically, the intent of the SAR was to maintain the intent and underlying obligations of CIP-002-6 Attachment 1, Criterion 2.6 while accommodating revisions to other reliability standards. Thus, a modification of the underlying obligation and impact of CIP-002-6 Attachment 1, Criterion 2.6 is not what the SAR intended. The proposed modification results in an expansion of the underlying obligations of Responsible Entities that will identify new and different facilities. For this reason, the proposed modification goes beyond what is necessary to accommodate the change from the other Standard. It is notable that the previous language hinged upon those facilities critical to the derivation of an IROL while the modification completely shifts the focus to those facilities that would result in system instability, cascading, or controlled separation. This is significant and forms our second reason for disagreement with the proposed modification.

In particular, the second reason is that not all events that result in system instability, cascading, or controlled separation would result in an IROL. Thus, not all facilities that, if lost or degraded, would result in an IROL or the derivation of an IROL, which was previously the focus of this requirement. This modification, therefore, pulls in results and facilities implicated during "extreme events" as defined in TPL-001-4, which is too broad and a far distance from the previous intent of CIP-002-6 Attachment 1, Criterion 2.6.

Finally, the third reason for AZPS's disagreement is the fact that the Transfer Capability Study is not intended to stress the system in those ways that would reveal an IROL. These studies are designed to identify those transfers that can be reliably accommodated. Exceedance of reliable accommodation of a transfer does not automatically translate to either the occurrence of system instability, cascading, or controlled separation or an IROL. Accordingly, the proposed modification goes beyond the current intent of CIP-002-6 Attachment 1, Criterion 2.6 and the intent of the SAR.

To ensure consistency with the intent of CIP-002-6 Attachment 1, Criterion 2.6 and the SAR associated with the proposed modification, APS proposes the following language for Criterion 2.6. This revision also clarifies that CIP-002-6 Attachment 1, Criterion 2.6 is not applicable to Extreme Events that are also studied with the Planning Assessment:

2.6 Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner as an element of each P0 – P7 Contingency event included in the Planning Assessment that result in System instability, Cascading or uncontrolled separation.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

No

Document Name

Comment

NV Energy is concerned that the use of term 'instability', within the context of Criterial 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES cyber assets to medium impact, while creating the potential for other BES cyber assets to be reclassified to high impact, while posing little to no known risk to BES reliability.

NV Energy suggests the insertion of "Wide Area impact" into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing "instability, Cascading, or uncontrolled separation." Example language follows:

"2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of Wide Area impacts such as instability, Cascading, or uncontrolled separation."

Alternatively, should the SDT chooses to leave the term 'instability' within CIP-002-6, NV Energy suggests minimizing the scope through language similar to what is currently used in the GTB for Criterion 2.9 which ties the term instability to Wide Area impacts. This would be consistent with the scope of CIP-014 that limits the scope of instability to within an Interconnection.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the "date of notification or detection of the Unplanned Change." The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

- The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:
 - prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.
 - after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.

The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer

No

Document Name

Comment

We are concerned that the language in Criteria 2.6 could cause new generation assets to be identified as needing to meet CIP-002-6 medium/high impact criteria for a short time frame until a Corrective Action Plan could be implemented. Additionally, current generation that is not medium could possibly become medium as other generation is retired if the retirement caused a change in IROLs. Could the language be modified to be a “newly identified issue that will not be obviated within 3 years”?

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

No

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

Insert Wide Area impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing “instability, Cascading, or uncontrolled separation.” Example language follows:

“2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of Wide Area impacts such as instability, Cascading, or uncontrolled separation.”

The standard must provide clarity on timing in 2.6 with the addition of Near-Term Planning Horizon. For example, a Facility projected to be medium impact five years out, should not be subject to CIP compliance in year one. Also, an entity should have, at a minimum, the months in the implementation plan for unplanned changes. Example language follows.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the “date of notification or detection of the Unplanned Change.” The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

- The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:
 - prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.
 - after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.
- The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

No

Document Name

Comment

Duke Energy is unclear on the language, and the necessity of bringing the Elements in as they are proposed in this standard. First, the terms System instability, Cascading, or uncontrolled separation may be interpreted differently depending on the PC/TP. The proposed criteria introduce a level of subjectivity that was intentionally eliminated from Version 5. Second, the term “Planning Assessment” is used which includes evaluation of Extreme Events under TPL-001. Providing a Medium impact classification to Facilities that are only identified during an Extreme Event is inappropriate. Third, with respect to generation, criterion 2.3 currently addresses a generation Facility that has been designated to avoid an Adverse Reliability Impact. The proposed criterion 2.6 is potentially duplicative with respect to generation. Fourth and most importantly, TP/PC identified SOLs/IROLs are proposed to be removed from the FAC standards. We are unclear why identification would be unnecessary in FAC-010, but those same Facilities that would have been identified are important enough to be labeled as Medium impact in this CIP standard.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer No

Document Name

Comment

Insert Wide Area impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing “instability, Cascading, or uncontrolled separation.”

Example language follows:

“2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of **Wide Area** impacts such as instability, Cascading, or uncontrolled separation.”

The standard must provide clarity on timing in 2.6 with the addition of Near-Term Planning Horizon. For example, a Facility projected to be medium impact five years out, should not be subject to CIP compliance in year one. Also, an entity should have, at a minimum, the months in the implementation plan for unplanned changes. Example language follows.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the “date of notification or detection of the Unplanned Change.” The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:

-- prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.

--after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.

--The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

ATC is concerned that the proposed changes eliminate consideration of Operating Horizon IROLs and may pose unintended consequences for security and reliability because the proposed wording will eliminate consideration of Facilities critical to the derivation of Operations Planning horizon IROLs. This change would eliminate the identification (and subsequent protection) of medium impact BES Cyber Systems that have a medium reliability impact in the Operations Planning horizon, but do not have a medium reliability impact in the Near-Term Planning horizon.

For this reason, ATC requests SDT consideration of the following wording for Criterion 2.6. which is similar to the present wording, "Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies".

This proposed alternate wording is based on the following considerations:

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes	0
-------	---

Dislikes	0
----------	---

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

EEL is concerned that the use of term 'instability', within the context of Criterial 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES cyber assets to medium impact, while creating the potential for other BES cyber assets to be reclassified to high impact, while posing little to no known risk to BES reliability. Whereas we recognize the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has always been limited in scope to specific reliability impacts to the Bulk Electric Systems. While EEL cannot accurately quantify the broad impacts of this proposed change, we understand that the potential exists for virtually every BES generator and BES Transmission Cyber Asset to be reclassified under the medium impact criteria. Additionally, we also understand that many generators with a Control Center within the physical boundaries of that facility would also likely to become high impact BES Cyber Assets, whether or not an IROL was impacted. Therefore, without some limiting minimum threshold that might inform companies as to the intended scope of these changes we cannot support the proposed changes.

Alternatively, should the SDT chooses to leave the term 'instability' within CIP-002-6, EEI suggests minimizing the scope through language similar to what is currently used in the GTB for Criterion 2.9 which ties the term instability to Wide Area impacts. This would be consistent with the scope of CIP-014 that limits the scope of instability to within an Interconnection.

Additionally, EEI is concerned that existing language used in Criterion 2.6 could be interpreted to mean that a BES Cyber System identified over the Near-Term Transmission Planning Horizon as Medium Impact could be understood to mean that an entity would be required to demonstrate CIP compliance within 12 or 24 months (See Scenario of Unplanned Change, page 6) from its initial identification even if the BES Cyber System would not be impacted until year five. For this reason, we ask the SDT to consider adding language similar to that used within TPL-001-4, Requirement 2.7, which we believe would remove all ambiguity.

Likes 0

Dislikes 0

Response

Randy MacDonald - NB Power Corporation - 1

Answer

No

Document Name

Comment

Does "Facilities lost or degraded" correlate with those events in table 1 of TPL-001-4? If not please point to the PC/TP Planning Assessment requirements that would identify those Facilities under section 2.6.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer

No

Document Name

Comment

ITC Supports the comments filed by the NSRF:

The NSRF proposes the following new wording for Criterion 2.6. which is similar to the present wording, "Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies".

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROs.

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer No

Document Name

Comment

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) believes the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6 is inconsistent with the Near-Term Planning Assessment required for TPL-001-4. It is also unclear whether the Planning Assessment required for TPL-001-4 can be used for Criterion 2.6 or additional studies are required.

Additionally, CenterPoint Energy is concerned that existing language used in Criterion 2.6 could be interpreted to mean that a BES Cyber System identified over the Near-Term Transmission Planning Horizon as Medium Impact could be understood to mean that an entity would be required to demonstrate CIP compliance within 12 or 24 months (See Scenario of Unplanned Change, page 6) from its initial identification even if the BES Cyber System would not be impacted until year five. For this reason, we ask the Standard Drafting Team (SDT) to consider adding language similar to that used within TPL-001-4, Requirement 2.7, which we believe would remove all ambiguity.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer No

Document Name

Comment

The PC and TP are not listed in the Applicability Section, nor are they associated with the Operations Planning Horizon. Listing them as responsible and providers of the list of Facilities without a direct linkage in the functional model may cause missing some facilities.

as for the removal of the RC from the criteria, there is concern regarding any identified PERMANENT IROLs that may be identified that will not be elevated under CIP concerns. WAPA agrees that temporary local instances of instability should not warrant elevated CIP concern, but does support industry concerns regarding removing the RC from the criteria.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

No

Document Name

Comment

The term “instability” is without limitation and, as such, has wide ranging implications for entities as they reassess low, medium, and high BES Cyber Systems impacts.

The companies recommend rationalizing “instability” with the NERC Glossary Term “System.”

System: “A combination of generation, transmission, and distribution components.”

The proposed revision:

“...Facilities, that, if lost or degraded are expected to result in instances of **System** instability, Cascading, or uncontrolled separations.”

This recommendation also aligns with the NERC Glossary Term, Cascading, “...loss of system elements...”; and uncontrolled separations.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

No

Document Name

Comment

Southern Company's main concern with the proposed change is not the substitution of the IROL term with the three outcomes – instability, Cascading, or uncontrolled separation – our main concern is the prescriptive nature of naming Planning Coordinator studies in Criteria 2.6 to consider, which is beyond existing IROL methodologies, and the use of the unbounded term “instability”.

The original CIP-002-5.1a language was specific to IROLs and Southern Company, like many other companies, has an IROL methodology that is largely based in RC and PC stability input. The new Draft CIP-002-6 shifts to the PC/TP and to the three outcomes and goes on to reference two specific studies we relate to TPL-001-4/-5 and FAC-013. This significantly alters the previous requirement language into a new requirement as these two studies were not the basis of the IROL methodology. We suggest that references to specific compliance-based studies such as TPL-001 and FAC-013 be removed and allow the use of in-place proven study methodologies to determine and communicate scenarios that are realistic potential instances of instability, Cascading, or uncontrolled separation.

Considering how current PC analysis addresses or may be used, TPL-001-4 Extreme Events steady-state requires consideration of Item 2c loss of a switching station or substation (loss of one voltage level plus transformers), and Item 2d loss of all generating units at a generating station. The issue we have is TP is not required to look at all Transmission Facilities at a single station or substation – only one voltage level. Additionally, TPL-001-4 only requires performing a steady-state analysis for items 2c and 2d – but not stability. TPL-001-4 R6 requires an Entity to define a methodology to analyze Cascading, voltage instability, or uncontrolled islanding. Per this methodology, Cascading is analyzed with the steady-state and stability modeling, and the other two are only part of stability (dynamic study) modeling as per R6 methodology. Since stability studies are not required per TPL-001-4 for loss of entire generating plants or transmission substations – this creates a conflict in the currently proposed language.

FAC-013 Transfer Capability assessment requires the PC to develop a methodology for analysis, but there is no requirement to consider loss of “Generation at a single plant location or Transmission Facilities at a single station or substation location” and therefore this also creates a conflict in the currently proposed language.

The SOL SDT is considering adding new / revising existing definitions of IROLs and associated phenomena (such a System Instability, a re-work of Cascading, etc). If so, the impacts on the CIP standards would have to be re-visited. Southern is concerned that the timing of these proposed changes in CIP-002 should be postponed until the SOL SDT modifications to defined terms are finalized and can be more properly incorporated into CIP-002, Att 1 Criteria.

Southern also requests the SDT consider that Criteria 2.3 and the new 2.6 are now duplicative based on the proposed changes, and that the SDT should consider the following proposal:

{C}1. Criteria 2.3: Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an **Adverse Reliability Impact** in the planning horizon of more than one year.

{C}2. Adverse Reliability Impact: The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.

{C}3. Criteria 2.6 (SDT Proposed): Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer

Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

Southern recommends the following changes to obtain consistency between Criteria 2.3 and Criteria 2.6 by modifying Criteria 2.3 and removing Criteria 2.6:

{C}· *Criteria 2.3 (Southern Proposed): Generation at a single plant location or Transmission Facilities at a single station or substation location that the Planning Coordinator or Transmission Planner designates, and informs the Generation Owner or Generator Operator, or Transmission Owner or Transmission Operator, as necessary to avoid Adverse Reliability Impact in the planning horizon of more than one year.*

{C}· *Criteria 2.6 (Southern Proposed): Removed and combined w. Criteria 2.3 as of CIP-002-6.*

Some supporting justification for the modification of Criteria 2.3 and the removal of Criterion 2.6 are:

{C}1. The time horizon for CIP-002-6 is “Operations Planning”, so Operational Planning Analysis, not “Near-Term Transmission Planning Horizon analysis”, is appropriate for any evaluation of potential Operating Horizon instability, Cascading, or uncontrolled separation;

{C}2. The consistent use of the NERC defined term Adverse Reliability Impact addresses the components of the previously used IROL definition, and consolidates two separate Criteria dealing with PC/TP studies and identification of critical Facilities for both Generation and Transmission;

{C}3. The consistent use of the NERC defined term Adverse Reliability Impact also properly scopes the PC/TP identification of critical Facilities to the Operations Planning horizon that results in subsequent evaluation of assets potentially containing BES Cyber Systems. It is not feasible to consider, and creates conflicts with existing Planned and Unplanned Change requirements, to have to potentially commission (or decommission) CIP assets based on the results of “Near-Term Planning Assessments”.

If Criteria 2.6 is to remain in the CIP-002-6 Standard, the wording should remain unchanged from the existing, approved language. The existing wording allows operating horizon IROLs to be evaluated using Operations Planning analysis, rather than requiring the use of Near-Term Transmission Planning Horizon analysis. Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards, and they will continue to do so based on the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2015-09.

CIP-002-6 R1 is an Operations Planning Horizon requirement and the FAC-011 and FAC-014 standards provide methodology and criteria details that are pertinent to an Operations Planning evaluation. Only operating horizon IROLs should presently apply to Criteria 2.6. For example, compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances caused by Planning Events to be identified and mitigated before the Operations Planning Horizon begins. Therefore, through this mitigation, there should be minimal Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners that identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

Southern Company is concerned that the use of term ‘instability’, within the context of Criterion 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES Cyber Systems to higher impact classifications when there has been no change in risk to BES reliability. The language provided in the GTB appears to have the intent of limiting the scope to Wide Area impacts, but unfortunately this is not reflected in the plain language in Criterion 2.6 or Criteria 2.9. This inconsistency between the GTB and Criterion could lead to confusion and inconsistent results. Southern suggests incorporating the consistent use of the term Adverse Reliability Impact to properly scope the Criterion requirements (See additional comments under question 2). This would be consistent with the scoping of CIP-014 that limits the scope of instability to within an Interconnection.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer No

Document Name

Comment

The standard claims the Medium Impact Rating criteria mentioned in Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify the BES cyber systems in accordance with the impact on the BES. However, the proposed changes to Medium Impact Rating Criterion 2.6 seem to be far away from “bright-line.”

Especially, use of the terms like “instances of instability,” “Cascading,” and “uncontrolled separation.” This is very dependent on each transmission planner’s criteria, methodology and threshold for the above items and could vary considerably even between the Planning Coordinator’s Assessment and the Transmission Planner’s Assessment. For example “instances of instability” may be limited one small generator or it may impact multiple generators in a region.

Suggest the standard drafting team come up with more specific methodology in place of IROL or delete this Criterion.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer No

Document Name

Comment

Exelon is concerned with the use of the term 'instability' within Criterion 2.6, inconsistent with how it is used in the GTB for Criterion 2.9. Use of this term should be limited to Wide Area impacts.

More clarity is also needed on the timing related to Near-Term Transmission Planning Horizon, to avoid subjecting a Facility projected to be medium impact five years out to CIP compliance in year one. Consider adding language similar to that used within TPL-001-4, Requirement 2.7, which would help remove ambiguity.

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

SRP Agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer

Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer

Yes

Document Name

Comment

This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator).

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator).

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer

Yes

Document Name

Comment

This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator)

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE

Answer

Yes

Document Name

Comment

SMEC suggest the SDT insert **Wide Area** impact into the requirement and in the supplemental material for Criterion 2.6 when referencing “instability, Cascading, or uncontrolled separation.”

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2**Answer** Yes**Document Name****Comment**

We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator)

Likes 0

Dislikes 0

Response**Matthew Goldberg - ISO New England, Inc. - 2 - NPCC****Answer** Yes**Document Name****Comment**

The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002.

The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications.

Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.

Likes 0

Dislikes 0

Response**Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 1	Arkansas Electric Cooperative Corporation, 6, Walkup Bruce
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**David Jendras - Ameren - Ameren Services - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**William Sanders - Lower Colorado River Authority - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

2. Attachment 1, Criterion 2.9: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.9? If not, please provide your rationale and an alternate proposal.

Chris Scanlon - Exelon - 1

Answer No

Document Name

Comment

Exelon believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not incorrectly identified as medium impact BES Cyber Systems. As demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.

Likes 0

Dislikes 0

Response

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer No

Document Name

Comment

Tri-State agrees with the comments submitted by Barry Lawson of NRECA.

In addition, Tri-State suggest the new Criterion 2.9 should read, "Each Remedial Action Scheme (RAS) that operates BES Elements identified by the Planning Coordinator in accordance with PRC-012-2 R4.1, as not being limited impact RAS." If the drafting team adopts this revision, Criterion 3.5 should also be modified so it is clear that only limited impact RAS qualify as Low Impact.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

No

Document Name

Comment

Southern Company views the inclusion of the term “Wide Area” in the Guidelines and Technical basis, but its absence in the Att 1 Criteria 2.9 language, to be a significant variance. As proposed in the comments for Criteria 2.3 and Criteria 2.6 above, Southern recommends the consistent use of the term Adverse Reliability Impact as a replacement for the previously used IROL reference. We think the phrase “Wide Area” as used in the G&TB is commensurate with the use of the term Adverse Reliability Impact when it comes to properly scoping the potential impact of BES Cyber Systems used in a RAS.

Attachment 1 - SoCo TP Proposed language:

2.9. Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent *Adverse Reliability Impact*. OR,

2.9 Each Remedial Action Scheme (RAS) where inadvertent operation or failure to operate could cause or contribute to instances of *Adverse Reliability Impact*.

Southern also feels a significant proposed change has been made to Criteria 2.9 that may not have been intended. With the new proposed language, all BES Cyber Systems associated with a RAS will be considered medium impact. This is a significant change from the current Criteria 2.9 where some RAS will be medium impact and others will be low impact (Att 1, Criteria 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. Southern requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged.

The proposed language used in Criterion 2.9 does not appropriately align with PRC-012-2, Requirement 4.3.1, which states the following:

“For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

The footnote further states:

“A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

For this reason, Southern asks the SDT to provide more clarity in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012, limited impact RAS should be classified as low impact.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

No

Document Name

Comment

Incorporating by reference the companies' response to Question 1, we recommend rationalizing "instability" with the NERC Glossary Term "System."

System: "A combination of generation, transmission, and distribution components."

The proposed revision:

"Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent **System** instability, Cascading, or uncontrolled separations."

This recommendation also aligns with the NERC Glossary Term, Cascading, "...loss of system elements..."; and uncontrolled separations.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer

No

Document Name

Comment

WAPA supports the comments of the NSRF, in particular: "consider rewording Criterion 2.9 to "Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation." [reference PRC-012-2, 4.1.3].

This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis"

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer No

Document Name

Comment

CenterPoint Energy believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer No

Document Name

Comment

Similar to our comments in response to Question 1, EEI is troubled by the proposed language in Criterion 2.9 largely due to the continued use of the unbounded term ‘instability’. While we believe the SDT did not intend to include local events that would not impact BES reliability, clarifications provided in the Guideline and Technical Basis are insufficient given entities are bound to comply with the language within an approved Reliability Standard, not the GTB. Moreover, the proposed language used in Criterion 2.9 does not appropriately align with PRC-012-2, Requirement 4.3.1, which states the following:

“For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

The footnote further states:

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

For this reason, EEI believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

ATC is concerned that the introduction of new terminology for 'designed to prevent' could be subjective and believes existing wording from PRC-012-2 Part 4.1.3 could be leveraged to align the standards and objectives to those defined concepts.

For this reason, ATC requests SDT consideration of the following rewording of Criterion 2.9 to something like, "Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation." [reference PRC-012-2, 4.1.3]. This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer No

Document Name

Comment

We disagree with the draft language where all BES Cyber Systems associated with a RAS will be medium impact.

Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-4 R4.3.1 states, "4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." The footnote states, "A RAS designated as limited impact cannot, by inadvertent

operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, "Limited RAS are excluded."

Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing "instability, Cascading, or uncontrolled separation."

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer No

Document Name

Comment

We disagree with the draft language where all BES Cyber Systems associated with a RAS will be medium impact.

Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-4 R4.3.1 states, "4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." The footnote states, "A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, "Limited RAS are excluded."

Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing "instability, Cascading, or uncontrolled separation."

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer

No

Document Name

Comment

The undefined term 'instability' could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarification with respect to the term "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instability.

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

No

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer No

Document Name

Comment

NRECA believes a significant proposed change has been made to 2.9 that may not have been intended. With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. NRECA requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged.

In addition, on page 26, the 4th bullet under the “Managing Constraints” section (that begins on page 25), this bullet should be deleted since it refers to IROLs.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer No

Document Name

Comment

NV Energy disagrees with the current draft language, as it reads, where all BES Cyber Systems associated with a RAS will be identified as a medium impact asset.

Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-2 R4.3.1 states, “4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

The footnote states, “A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, “Limited RAS are excluded.”

Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing “instability, Cascading, or uncontrolled separation.”

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer

No

Document Name

Comment

AZPS is not in agreement with the proposed modifications to CIP-002-6 Attachment 1, Criterion 2.9. The language in CIP-002-6 Attachment 1, Criterion 2.9 and the Guidelines and Technical Basis of Criterion 2.9 are not in alignment because IROLs, by their nature, produce Wide Area impacts and this Wide Area designation is clear in the technical basis. That there is not an indication or designation of Wide Area impacts in Criterion 2.9 could result in local area RASs that do not affect the BES being identified pursuant to this Criterion. As stated above, local, non-BES impacts are not in alignment with the Wide Area designation in the technical basis nor the Wide Area impacts that are one of the hallmarks of an IROL. To ensure this alignment and properly retain the intent of Criterion 2.9, APS proposes the following language for CIP-002-6 Attachment 1, Criterion 2.9 to align it with the technical basis.

2.9 Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent Wide Area impacts such as instability, Cascading, or uncontrolled separation.

Likes 0

Dislikes 0

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer

No

Document Name

Comment

LES supports the following NSRF comments:

The NSRF recommends the deletion of Criterion 2.9 after the PRC-012-2 standard becomes effective. PRC-012-2 R3 requires any reliability issues with new or functionally modified RASs to be resolved prior to the RAS being placed in service and PRC-012-2 4.1 obligates limited impact RASs and 'other' RASs to meet stringent reliability performance requirements, which are sufficient to exempt them from being CIP-002-6 medium impact rating candidates. This approach would categorize all RASs as low impact rating assets due to the stringent limitations of the potential BES reliability impacts on PRC-012 compliant RASs. In addition, this approach is a more Brightline criteria than the proposed approach.

With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5).

If Criterion 2.9 is not removed, consider rewording Criterion 2.9 to "Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation." [reference PRC-012-2, 4.1.3].

This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

No

Document Name

Comment

The NSRF recommends the deletion of Criterion 2.9 after the PRC-012-2 standard becomes effective. PRC-012-2 R3 requires any reliability issues with new or functionally modified RASs to be resolved prior to the RAS being placed in service and PRC-012-2 4.1 obligates limited impact RASs and 'other' RASs to meet stringent reliability performance requirements, which are sufficient to exempt them from being CIP-002-6 medium impact rating candidates. This approach would categorize all RASs as low impact rating assets due to the stringent limitations of the potential BES reliability impacts on PRC-012 compliant RASs. In addition, this approach is a more Brightline criteria than the proposed approach.

With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5).

If Criterion 2.9 is not removed, consider rewording Criterion 2.9 to "Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation." [reference PRC-012-2, 4.1.3].

This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer

No

Document Name

Comment

The undefined term 'instability' could be interpreted to include strictly local events that could impact a single bus. The current use of 'instability' could be interpreted to include every RAS that interacts with the BES rather than the previous limitation to those RASs that impacted an IROL.

Dominion Energy recommends that the term 'instability' be eliminated from any of the Requirements and Attachments in CIP-002-6.

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Yes

Document Name

Comment

We generally agree with the proposed changes. However, NERC should modify Criterion 2.9 to make clear that RAS used for protection as opposed to "instability, Cascading or uncontrolled separation" is excluded from the determination of the medium impact rating.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

Yes

Document Name

Comment

GSOC agrees with that IROLs established by the RC is not an appropriate qualifier in the determination of Facilities that require cyber-related hardening as these limits may be related to be highly specific, temporary, or sudden onset types of events determined in operational and real-time horizons. The identification of these Facilities are more appropriately based on long-term planning studies.

Further, the alternate wording embedded in the Attachment 1 is an appropriate substitution in response to the proposed retirement of FAC-010-2. This wording incorporates the severe System impacts currently associated with IROLs so the intent of the criterion is preserved.

GSOC do recommend the SDT consider incorporating a qualifier for the term “instability” in the proposed criterion to make clear that the criterion is referring to System impacts. A potential wording modification could be as follows:

Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent instability, Cascading, or uncontrolled separation on the System (or system).

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer Yes

Document Name

Comment

Request explanation of why changing from the older CIP (IROL) phrasing to the newer FAC (instability, cascading or uncontrolled separation) phrasing

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer Yes

Document Name

Comment

Request explanation of why changing from the older CIP (IROL) phrasing to the newer FAC (instability, cascading or uncontrolled separation) phrasing.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

SRP agrees with the proposed modifications in CIP-002-6, Criterion 2.9

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

William Sanders - Lower Colorado River Authority - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Matthew Goldberg - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 1 Arkansas Electric Cooperative Corporation, 6, Walkup Bruce

Dislikes 0

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer Yes

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE

Answer

Document Name

Comment

SMEC agrees with NRECA comments.

A significant proposed change has been made to 2.9 that may not have been intended. With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. NRECA requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged.

In addition, on page 26, the 4th bullet under the "Managing Constraints" section (that begins on page 25), this bullet should be deleted since it refers to IROLs.

SMEC also suggests the SDT insert **Wide Area** impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing "instability, Cascading, or uncontrolled separation".

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

3. Attachment 1, Criterion 2.12: No changes have been added from the previous ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer No

Document Name

Comment

It is Idaho Power Company's understanding that there are ongoing discussions within one or more Standards Drafting Teams (SDT) about the definition of a Control Center. It seems plausible to wait until those discussions are settled to make a change to this criterion rather than to try to make a change now and then potentially make another one down the road when those SDT discussions are settled.

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer No

Document Name

Comment

Comments: The current definition in 2.12 does not differentiate between the type of Transmission Line that is used in criteria 2.5 and 2.8. Should generator interconnection facilities be included in the count or not? Also, in the case of tie lines, Entity A may own the substation when Entity B has a breaker/relays, etc. The loop through breaker is owned by Entity B. Entity B officially is the TO/TOP; contractually Entity A has supervisory trip control due to proximity to Entity A's equipment and will only exercise that to protect and safeguard human life from possible injury or death, or, in an emergency to protect a part of Entity A's power system from damage. While both Entities are monitoring the line (along with the RC), Entity B is the Control Authority for that line/breaker and is including that line in its own calculation of 2.12 if Entity B is not already governed by 1.1 – 1.4. We believe that Entity A would be duplicating the count of the line if it is included under 2.12. Please clarify.

We recommend the clarification that lines identified/classified under Criterion 2.8 should not be included in the calculation of Criterion 2.12 Control Centers.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer No

Document Name

Comment

As submitted during the previous comment period for this standard, the proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators that currently have medium impact BES Cyber Systems because of 2.12; to become low impact.

For example:

- The use of the term “and” means that a TO that monitors but **does not control** is no longer classified as a medium BES Cyber Asset.
- A TO that monitors and controls a substation (A) that has three 345 kV lines and two 138 kV lines. Its “aggregated weighted value” would be $1300+1300+1300+250+250=4,400$. This TO also monitors and controls another substation (B) with one 345 kV lines and one 138 kV lines. Its “aggregated weighted value” would be $1300+250=1,550$. $4,400 (A)+1,550 (B) =5,950$, which is less than 6,000. Therefore, even though this TO may meet the definition of Control Center, the Control Center’s BES Cyber Systems would now be low impact even though the substation itself would have medium impact BES Cyber Systems (medium impact criteria 2.5).

Texas RE is concerned this will have a negative impact on reliability since less assets would be protected under the proposed revisions.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

No

Document Name

Comment

We do not agree with the 6000 point threshold in isolation. Rather, it should be determined in connection with connected assets. For example, if a control center controls a medium impacted rated substation then the control center should be designated as medium regardless of the weighted value per line total.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

SRP agrees with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer

Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer

Yes

Document Name

Comment

There is a discrepancy in word case for Criterion 2.11 and 2.13 between the requirement and the supplemental material. The word "Interconnection" is a NERC defined term (page 17 [here](#)), but is not consistently capitalized and I believe it should be. The outcome will not change our compliance requirements or responsibilities, but should make it more consistent across the document.

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name** FirstEnergy**Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Leanna Lamatrice - AEP - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name** MRO NSRF**Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 1 Arkansas Electric Cooperative Corporation, 6, Walkup Bruce

Dislikes 0

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Barry Lawson - National Rural Electric Cooperative Association - 4****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Anton Vu - Los Angeles Department of Water and Power - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Randy MacDonald - NB Power Corporation - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Matthew Goldberg - ISO New England, Inc. - 2 - NPCC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company**Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Julie Hall - Entergy - 6, Group Name** Entergy**Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

4. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

Chris Scanlon - Exelon - 1

Answer No

Document Name

Comment

Please add language to the GTB that addresses our concerns as provided through our comments for Question 1.

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer No

Document Name

Comment

“Instances of Instability, Cascading or Uncontrolled Separation” is a very vaguely defined criteria and is far away from the “bright-line” intent of Attachment 1 in this standard, please see our comments provided to Question 1.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

No. Please see the comments for question 1.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer No

Document Name

Comment

It would be helpful to add language to clarify how results from any new studies are shared with impacted asset owners.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer No

Document Name

Comment

The PC and TP are not identified in the Applicability Section, nor are the PC/TP involved in the Operations Planning Horizon.

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer No

Document Name

Comment

CenterPoint Energy recommends that the SDT provide greater clarity on the following concerns:

1. It is unclear whether the SDT is suggesting that additional studies be conducted for every generation and Transmission facility.
2. It is unclear whether the SDT's intended to create a new requirements for the Planning Authority and Transmission Planners.
3. It is unclear whether there are any obligations to ensure that the results from any new studies are appropriately shared with impacted asset owners.

In addition to the comments above, we ask the SDT to add language to the Guidelines and Technical Basis that addresses our concerns as provided through our comments for Question 1.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer No

Document Name

Comment

We agree with the proposed changes except as noted in our response to 3 above. The 6000 threshold for qualifying as a medium impact control center should not be made in isolation of the rating of relevant assets. For example, a control center that operates a medium impact station should be rated a medium impact, irrespective of the weighted value per line total.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer No

Document Name

Comment

ITC Supports the comments filed by the NSRF:

Please see comments for Question 1.

Likes 0

Dislikes 0

Response

Randy MacDonald - NB Power Corporation - 1

Answer

No

Document Name

Comment

Does "Facilities lost or degraded" correlate with those events in table 1 of TPL-001-4? If not please point to the PC/TP Planning Assessment requirements that would identify those Facilities under section 2.6.

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer

No

Document Name

Comment

EEL asks the SDT to provide greater clarity on the following concerns:

- 1. It is unclear whether the SDT is suggesting that studies be conducted for every generation and Transmission facility.*
- 2. It is unclear whether the SDT's intended to create a new requirements for the Planning Authority and Transmission Planners.*
- 3. It is unclear whether there are any obligations to ensure that the results from any new studies are appropriately shared with impacted asset owners.*

In addition to the comments above, we ask the SDT to add language to the GTB that addresses our concerns as provided through our comments for Question 1.

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer No

Document Name

Comment

Same comments as for Question # 1.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer No

Document Name

Comment

The Guidelines and Technical Basis (actually Supplemental Material) for Criterion 2.6 should be changed to address comments on Question 1.

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer No

Document Name

Comment

We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

Suggest different wording since instability may be based instability - "Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena such as instability or voltage collapse" . . . should not use the word being defined in the definition

We understand that the CIP-002 experts expects someone else to provide this operations assessment list. Why is this not explicitly stated?

Suggested revised language:

Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena (e.g., voltage collapse, angular instability, transient voltage dip criteria violation).

The Standard and GTB should explicitly reference FAC-015 Requirement 4, since the Transmission Planner that performs the FAC-015 assessment needs to tell the CIP-002 Asset Classification SME which assets, if lost, would result in instability, Cascading, or uncontrolled separation. Similarly, FAC-015 should include some kind of reference back to CIP-002-6, not necessarily in Requirement 4, but perhaps in the GTB for FAC-015.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

The Guidelines and Technical Basis (actually Supplemental Material) for Criterion 2.6 should be changed to address comments on Question 1.

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer

No

Document Name

Comment

The undefined term 'instability' could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarification with respect to the term "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instability.

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
The GTB may need to be revised if comments in question 1 and question 3 are addressed.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy asks the SDT to add language to the GTB that addresses our concerns as provided through our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	

Comment

AZPS is not in agreement with the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.6. As described in its comments in response to Question 1 and for the same reasons, the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.6 revise and expand the underlying obligation of Responsible Entities, which is beyond the intent of the associated SAR.

Likes	0
-------	---

Dislikes	0
----------	---

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer	No
--------	----

Document Name	
---------------	--

Comment

Please see our comments for Question 1.

Likes	0
-------	---

Dislikes	0
----------	---

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
--------	----

Document Name	
---------------	--

Comment

The Guidelines and Technical Basis does not appear to say much more than the criterion itself. More information would be helpful to provide guidance in the implementation of the criterion and the proposed change.

Likes	0
-------	---

Dislikes	0
----------	---

Response

David Rivera - New York Power Authority - 3

Answer No

Document Name

Comment

We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

Suggest different wording since instability may be based instability - "Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena such as instability or voltage collapse" . . . should not use the word being defined in the definition.

We understand that the CIP-002 experts expects someone else to provide this operations assessment list. Why is this not explicitly stated?

Suggested revised language:

Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena (e.g., voltage collapse, angular instability, transient voltage dip criteria violation).

The Standard and GTB should explicitly reference FAC-015 Requirement 4, since the Transmission Planner that performs the FAC-015 assessment needs to tell the CIP-002 Asset Classification SME which assets, if lost, would result in instability, Cascading, or uncontrolled separation. Similarly, FAC-015 should include some kind of reference back to CIP-002-6, not necessarily in Requirement 4, but perhaps in the GTB for FAC-015.

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer No

Document Name

Comment

Please see our comments for Question 1.

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer No

Document Name	
Comment	
Additional text should be added to make it clear that the RC, TP, or PC is expected to notify affected Responsible Entities.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
It is unclear if the studies in criterion 2.6 are required to be performed for every generation and Transmission facility and if the intent of the modification to 2.6 could create a new requirement of the Planning Authority and Transmission Planners. It is also unclear if there is a current requirement for the results of the studies to be shared with the studied Facility owners or if the internet is to create a new requirement. The potential communication gap created by this lack of clarity could result in Facility owners considering the criterion as not applicable to their Facilities.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	

Comment

The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002.

The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications.

Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE

Answer

Yes

Document Name

Comment

SMEC suggests the SDT insert **Wide Area** impact into supplemental material for Criterion 2.6 when referencing "instability, Cascading, or uncontrolled separation".

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

As written, It is already clear that the CIP-002 experts are not the one proceeding the operations assessment list. It should be the transmission planner or planning coordinator.

Likes 0

Dislikes 0

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

The term Transfer Capability assessment is not a defined term in the NERC Glossary, so the word "assessment" should not be capitalized as it is in the GT&B section and other places in the document.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard

Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

5. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

The GTB document appears to have the intent of limiting the scope of the criterion to only Wide Area impacts, which is not reflected in the word of the actual criterion in Appendix 1. This inconsistency between the GTB and the words of the criterion could lead to confusion and inconsistent results.

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer No

Document Name

Comment

Please see our comments for Question 2.

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer No

Document Name

Comment

Is criterion 2.9 associated with any other NERC Standards / Requirements like 2.6? If yes, what other NERC Standards / Requirements?

Criterion 2.9 in the GTB includes a "Wide Area" qualifier that is not present in the version of criterion 2.9 in Attachment 1 – Impact Rating Criteria. Recommend removing the term "Wide Area" from the GTB.

Likes 0

Dislikes 0

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer No

Document Name

Comment

Please see our comments for Question 2.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer No

Document Name

Comment

The Supplemental Material should be changed to address comments on Question 2.

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer No

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer No

Document Name

Comment

The undefined term 'instability' could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarification with respect to the term "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instability.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer No

Document Name

Comment

The Supplemental Material should be changed to address comments on Question 2.

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Quebec TransEnergie - 1

Answer No

Document Name

Comment

Criteria 2.9 seems more general and do not have any connection with the criteria 2.6. As the focus on the BES elements that if lost or degraded can cause instability, Cascading or uncontrolled separation. We propose the following text:

"2.9 Each remedial Action Scheme (RAS) that operates BES elements that if lost or degraded can cause instability, Cascading or uncontrolled separation".

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer

No

Document Name

Comment

Is criterion 2.9 associated with any other NERC Standards / Requirements like 2.6? If yes, what other NERC Standards / Requirements?

Criterion 2.9 in the GTB includes a "Wide Area" qualifier that is not present in the version of criterion 2.9 in Attachment 1 – Impact Rating Criteria. Recommend removing the term "Wide Area" from the GTB.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

No

Document Name

Comment

The Supplemental Material should be changed to address comments on Question 2.

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer

No

Document Name

Comment

Same comments for Question # 2.

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer

No

Document Name

Comment

EEI believes the language provided in the GTB appears to have the intent of limiting the scope of the Criterion 2.9 to only Wide Area impacts, unfortunately this is not reflected in the plan language in Criterion 2.9. This inconsistency between the GTB and Criterion 2.9 could lead to confusion and inconsistent results.

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

No

Document Name

Comment

CenterPoint Energy notes that the language provided in the the Guidelines and Technical Basis may be interpreted as limiting the scope of the Criterion 2.9 to only Wide Area impacts, which is not reflected in the plan language in Criterion 2.9. This inconsistency between the Guidelines and Technical Basis and Criterion 2.9 could lead to confusion and inconsistent results.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer

No

Document Name

Comment

The language may create an unintended compliance issue. Specifically, it identifies a result, "Wide Area impacts," that are not mentioned in Criterion 2.9. Including the reference establishes a compliance threshold. Since G&TB documents are not enforceable, establishing a compliance threshold is inconsistent with the NERC Rules of Procedure.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

No

Document Name

Comment

No. Please see the comments for question 1.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer

No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer

No

Document Name

Comment

The guidelines and technical basis should be changed to align with the new approach for Criterion 2.9.

Likes 0

Dislikes 0

Response

Chris Scanlon - Exelon - 1

Answer

No

Document Name

Comment

Please address along with comments in Question 2. Inconsistency between the GTB and Criterion 2.9 could lead to confusion and inconsistent results.

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

SRP agrees with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer Yes

Document Name

Comment

AZPS is in agreement with the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.9. As described in its comments in response to Question 2, AZPS recommends that Attachment 1, Criterion 2.9 is modified in order to align with Criterion 2.9 of the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.9.

Likes 0

Dislikes 0

Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We generally agree with the proposed changes. However, NERC should modify Criterion 2.9 to make clear that RAS used for protection as opposed to "instability, Cascading or uncontrolled separation" is to be excluded from the determination of the medium impact rating.	
Likes	0
Dislikes	0
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Richard Jackson - U.S. Bureau of Reclamation - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Dennis Sismaet - Northern California Power Agency - 6****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Laura Nelson - IDACORP - Idaho Power Company - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Randy MacDonald - NB Power Corporation - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

6. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Chris Scanlon - Exelon - 1

Answer No

Document Name

Comment

Exelon is concerned that if the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, as well as requiring limited impact RAS to be reclassified as medium impact BES Cyber Systems the resulting impact to the industry would be exceedingly large and well beyond the 15 months provide in the proposed implementation plan. Therefore, without changes to address our concerns we cannot support the proposed Implementation Plan.

Likes 0

Dislikes 0

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer No

Document Name

Comment

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer No

Document Name

Comment

EEI is concerned that if the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, as well as requiring limited impact RAS to be reclassified as medium impact BES Cyber Systems the

resulting impact to the industry would be exceedingly large and well beyond the 15 months provide in the proposed implementation plan. Therefore, without changes to address our concerns we cannot support the proposed Implementation Plan.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

No

Document Name

Comment

As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, these changes should not be effective before PRC-012-2.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, these changes should not be effective before PRC-012-2.

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name	
Comment	
To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard.	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
<p>Our comments are peripherally related to the Implementation Plan but also extend to the Section 5 included in CIP-002-6. We are concerned with the Near-Term Planning Assessment language and the "Section 5 Planned and Unplanned Changes" implementation table. The timeframe might be sufficient for a substation to come into compliance but it is unlikely that a new medium impact generating plant designated under the proposed 2.6 would be able to meet the compliance obligations. If an Entity that owns low impact assets containing BES Cyber Systems, the Entity will need significantly more time to develop a full-blown CIP program if they are brought into the CIP compliance obligation by the PA or TOP.</p> <p>Scenario of Unplanned Change - New medium impact BES Cyber System where the Responsible Entity has not previously identified a medium or high impact BES Cyber System.</p> <p>Implementation Period - 36 calendar months from the date of notification or detection of the Unplanned Change.</p>	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore, 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, NV Energy believes that these changes should not be effective prior to the effective date of PRC-012-2.	

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer

No

Document Name

Comment

While AZPS appreciates that the SDT is now proposing a 15 month implementation timeline, it continues to remain concerned that a longer timeline is necessary. Accordingly, AZPS reiterates its previous comments that the implementation time period be 24 calendar months from the date of notification or detection of the unplanned changes regardless of whether or not the Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type as the effort required would involve the design and implementation of technology, procurement, and contracting efforts, which could easily exceed 15 months.

Likes 0

Dislikes 0

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer

No

Document Name

Comment

A longer implementation time period is needed. Instead of 15 months after the effective date of the applicable governmental authority's order approving the standard, the revised standard should become effective the first day of the first calendary quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard.

This is to allow additional needed time for entities to prepare, plan, budget, procure, and hire additional labor resources to meet all the applicable reliability standards in becoming a Medium or High Impact entity from an existing Low-Impact entity. Cost estimates from consultants range anywhere from \$100,000.00 for consultant fees only, to \$1 million or more depending on computer hardware, facility hardening, and security software. This is especially burdensome for smaller entities, such as NCPA, who need more time, money, and approvals from it's governing board to make sure we have the funds and resources to properly prepare for and meet the new CIP reliability requirements.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	
Comment	
Reclamation recommends CIP-002-6 become effective no earlier than 18 months after the applicable governmental entity's order approving the standard to allow entities flexibility to determine the appropriate implementation.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	
Comment	
To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard.	
Likes 0	
Dislikes 0	
Response	

Leanna Lamatrice - AEP - 3**Answer** No**Document Name****Comment**

The 15 months provided in the Implementation Plan for establishing the effective date is reasonable, however AEP believes that the allowance for an Unplanned Change (within the Standard itself) is not sufficient. As currently proposed, it does not provide sufficient time to accomplish all the physical changes necessary to move from compliance for an asset containing low impact BES Cyber Systems to one where all the BES Cyber Systems are instantly categorized as medium. Instead, 24 months should be permissible whether or not the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type. AEP recommends the Unplanned Changes Section be updated to address this and any other similar set of circumstances. Please note that AEP's negative ballots are primarily driven by our concerns expressed in this response to Question #6.

Likes 0

Dislikes 0

Response**Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name** Dominion**Answer** No**Document Name****Comment**

If the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, at a minimum, then a phased implementation plan over a minimum period of 7-10 years could be necessary to budget and physically upgrade all of the applicable low impact assets to meet the requirements for a medium impact asset.

Likes 0

Dislikes 0

Response**Chris Wagner - Santee Cooper - 1, Group Name** Santee Cooper**Answer** No**Document Name****Comment**

Before approval and enforcement a couple of changes need to be made. Everywhere they refer to MOD-024 they need to change it to MOD-025. MOD-024 was never approved. MOD-025 contains both MOD-024 and 025.

Likes 1

Nebraska Public Power District, 3, Eddleman Tony

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer No

Document Name

Comment

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer Yes

Document Name

Comment

CenterPoint Energy agrees with the Standard Drafting Team’s proposed Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.

However, CenterPoint Energy believes the implementation timeline for planned changes resulting in a higher categorization as proposed in CIP-002-6 is not consistent with the concept in the current CIP Version 5/6 implementation plan. Page 4, paragraph 3 of the “Implementation Plan for Version 5 CIP Cyber Security Standards” states that for planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements **“on the update of the identification and categorization of the affected BES Cyber System,”** not “upon the commission date of the planned change” as proposed in CIP-002-6.

CenterPoint Energy recommends removing the phrase “or a change in categorization for an existing BES Cyber System” from the second paragraph in section 6 to keep it focused on planned changes resulting in a new BES Cyber System and adding the following paragraph for planned changes resulting in a higher categorization:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets.”

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

As submitted during the previous comment period for this standard, Texas RE inquires as to why the section regarding planned and unplanned changes was removed from the implementation plan. Since they no longer reside in one of the enforceable parts of the standard, this will cause confusion upon implementation. Texas RE recommends keeping this section in the implementation plan.

Texas RE also noticed that PCAs were removed from the graphic on page 7, but is still in the list of Cyber Assets on page 9.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

SRP agrees with the Implementation Plan

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

William Sanders - Lower Colorado River Authority - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Matthew Goldberg - ISO New England, Inc. - 2 - NPCC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nicholas Lauriat - Network and Security Technologies - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Rivera - New York Power Authority - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name	
Comment	
We neither agree nor disagree. Note, however, that 15 months may impact the ability to implement RAS additions.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

7. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer No

Document Name

Comment

Section 6 Under New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type – 24 calendar months from the date of notification or detection of the Unplanned Change.

24 Months is not enough time to take a Low Impact Facility and bring it into compliance as a Medium especially for a generation facility. Budgets, new BES System design, equipment delivery, installation of equipment and patching, writing procedures, policy and processes, creating evidence and documentation are required to go from a Low Impact to a Medium Impact System and remain in compliance. This needs to be 48 Months to be completed cost effectively.

Likes 1 Nebraska Public Power District, 3, Eddleman Tony

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

The apparent intent to expand the scope of medium and high impact Cyber Assets does not appear to be a cost effective use of resources for the reliability benefit to be gained.

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer No

Document Name

Comment

The NSRF request that Section 6 "Background" is removed completely or moved to the Guideline and Technical Basis section. The entire Guideline and Technical Basis section should be removed from the Standard as it may be interpreted as how to meet the Compliance obligations of the Requirements. FERC Order 693 section 253 states, "The most critical element of a Reliability Standard is the Requirements. As NERC explains, "the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA." This information should reside outside the Standard as a NERC Compliance Guidance document.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer

No

Document Name

Comment

NO, WE DO NOT ARGEE, as the language of the "Planned Changes" treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, "upon commissioning" compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately "upon commissioning") and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.

- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered "non-critical" cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.
- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. ...12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a "planned" modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0

Dislikes 0

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer

No

Document Name

Comment

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

- Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.
- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.
- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. ...12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer No

Document Name

Comment

We are concerned that the language in Criteria 2.6 could cause new generation assets to be identified as needing to meet CIP-002-6 medium/high impact criteria for a short time frame until a Corrective Action Plan could be implemented. Additionally, current generation that is not medium could possibly become medium as other generation is retired if the retirement caused a change in IROLs. Could the language be modified to be a "newly identified issue that will not be obviated within 3 years"?

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer No

Document Name

Comment

Prior to proposing additional modifications, Reclamation recommends each SDT take additional time to effectively define the scope of each Standard Authorization Request to minimize the costs associated with the planning and adjustments required to achieve compliance with frequently changing requirements. This will provide entities with economical relief by allowing technical compliance with current standards.

Reclamation also recommends the SDT use existing NERC Glossary of Terms or follow procedures for adding new terms to the NERC Glossary of Terms. For example, Planned and Unplanned Changes are identified within the standard and are not listed within the NERC Glossary of Terms.

Likes 0

Dislikes 0

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer No

Document Name

Comment

There is no reason to change the existing two year time period in preparing to meet the new Medium or High impact CIP reliability requirements. The new requirement to start the clock running when a contract with a customer is signed to provide control center operation services to manage their generation facilities doesn't make sense if the net real power from the additional 100 MW nameplate capacity only results in 50 MW of net real power during the following summer months. It is possible that all the work, time, and money spent to go from Low to Medium impact based on a signed contract would be wasted if the net real power never reaches the 1500 MW threshold.

It would be better to keep the existing two year transition period which starts when the net real power reaches the 1500 MW threshold, regardless, when the control center operation service contract gets signed.

Likes 0

Dislikes 0

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer

No

Document Name

Comment

LES supports the following NSRF comments:

The NSRF request that Section 6 "Background" is removed completely or moved to the Guideline and Technical Basis section. The entire Guideline and Technical Basis section should be removed from the Standard as it may be interpreted as how to meet the Compliance obligations of the Requirements. FERC Order 693 section 253 states, "The most critical element of a Reliability Standard is the Requirements. As NERC explains, "the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA." This information should reside outside the Standard as a NERC Compliance Guidance document.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

No

Document Name

Comment

NV Energy does not believe that at this time, due to necessary changes for Criterion 2.6 and 2.9, are able to agree. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved. It would be clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional Comments:

- Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized.
- Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer

No

Document Name

Comment

We are concerned that the new language in Criteria 2.6 will cause new assets (big iron) to be identified as needing to meet CIP-002-6 medium impact criteria for a short time frame until a Corrective Action Plan could be implemented. This does not seem prudent to support from a ratemaking perspective, especially as generation is retired. Could the language be modified to be a “newly identified issue that will not be obviated within 3 years”? Otherwise, an Entity will spend considerable time and money to develop a CIP program that might not be required depending on the timeframe the Corrective Action is completed.

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

No

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

No

Document Name

Comment

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.

- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.
- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. ...12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0

Dislikes 0

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer

No

Document Name

Comment

Not at this time because changes for Criterion 2.6 and 2.9 are needed. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved It would be

clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional notes: Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized. Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

No

Document Name

Comment

: Not at this time because changes for Criterion 2.6 and 2.9 are needed. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved. It would be clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional notes: Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized. Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.

Likes 0

Dislikes 0

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer

No

Document Name

Comment

If the proposed wording for Criterion 2.9 remains unchanged, it could cause Registered Entities to incur additional administrative and financial burden. ATC believes a more cost effective approach would be to align the language in Criterion 2.9 with PRC-012-2 Part 4.1.3 so Registered Entities may use those RAS evaluations as an input to CIP-002. This approach offers a more holistic and consistent method for determining impact.

Likes 0

Dislikes 0

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
<p><i>At this time, EEI cannot support the SDT's belief that the current version of CIP-006-2 provides entities with flexibility to meet the reliability objectives intended for this Reliability Standard in a cost-effective manner. This is largely due to issues and concerns reflected in our comments associated with Criterion 2.6 and 2.9.</i></p> <p><i>Additional EEI Comments include the following:</i></p> <ol style="list-style-type: none"> <i>The term 'Planned and Unplanned Changes' should not be capitalized given this is not a defined term as found in the NERC Glossary of Terms.</i> <i>On page 29 (Redline version) of the Supplemental Material, a reference is made to MOD-024, however, MOD-024 was never approved. It was skipped in favor of MOD-025. This reference should be changed to MOD-025.</i> 	
Likes	0
Dislikes	0
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
<p>Incorporating our response to Question 1, without establishing bounds to the word "instability," the expected result potentially shifts BES Cyber Systems from low to medium and medium impact systems to high. Such a shifting of impacts is likely without improving BES reliability.</p> <p>If such is the case, the companies believe that the cost to implement Requirements without improving reliability is inconsistent with a cost-effective approach.</p>	
Likes	0
Dislikes	0
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1**Answer** No**Document Name****Comment**

See MidAmerican Energy Company comments.

Likes 0

Dislikes 0

Response**Chris Scanlon - Exelon - 1****Answer** No**Document Name****Comment**

At this time, Exelon cannot support the SDT's belief that the current version of CIP-006-2 provides entities with flexibility to meet the reliability objectives intended for this Reliability Standard in a cost-effective manner. This is largely due to issues and concerns reflected in our comments associated with Criterion 2.6 and 2.9.

Additional comments include the following:

1. The term 'Planned and Unplanned Changes' should not be capitalized given this is not a defined term as found in the NERC Glossary of Terms.
2. On page 29 (Redline version) of the Supplemental Material, a reference is made to MOD-024, however, MOD-024 was never approved. It was skipped in favor of MOD-025. This reference should be changed to MOD-025.

Likes 0

Dislikes 0

Response**Russell Martin II - Salt River Project - 1,3,5,6 - WECC****Answer** Yes**Document Name****Comment**

SRP agrees

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

ReliabilityFirst agrees with the proposed modification.

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

We thank the SDT for allowing us to provide comments on these standards.

Likes 0

Dislikes 0

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer Yes

Document Name

Comment

AZPS agrees that the proposed modification provide entities with flexibility to meet the reliability objectives, provided the implementation period is reasonable (i.e., 24 months). Otherwise it may require entities to expand significant resources to meet timeframes that may be unnecessarily short.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Southern Company also supports MRO's comments under Project 2015-09 Establish and Communicate System Operating Limits, which include:

The changes to CIP-002-6 criterion 2.6 and 2.9 do not add clarity. Unfortunately, the proposed changes to criterion 2.9 would bring in most SPS/RAS in the country because these systems are typically designed to avoid instability or a cascading outage scenario. Similarly, the proposed changes to criterion 2.6 substantially expands the scope of analysis. The current CIP-002-5.1 criterion 2.6 language is very clear and narrow because it limits the evaluation to those Facilities that have been shown to impact a large area of the system (i.e. what it means to be an IROL). With the proposed changes, many more Facilities will need to be evaluated for instability, but the end result will still be very few Facilities on the list (and those that make it on the list probably have an SPS/RAS to mitigate the concern). This appears to be an unneeded expansion of the criterion whereas the current language is precise. The SDT should keep in mind that IROLs will still exist under the proposed FAC standard revisions for the operating horizon and, therefore, no change is needed to R2.6 or R2.9.

Southern also recommends that the SDT consider the following:

The new 2.6/2.9 criteria are for TPL studies from TPL standards that only apply to a TP and PC. The criteria for those studies and the results of them are being placed in a CIP-002 Standard that does not even apply to TP or PC - it applies to RC/BA/TO/TOP/GO/GOP. These entities are required to have a process that considers each of the criteria in Attachment 1. If a TOP/GOP entity read the 2.6/2.9 criteria from a purely TOP/GOP perspective, you'll see that they can't prove those criteria. The only thing they could prove is whether or not they were officially notified by a TP/PC that they had such a facility, but there is nothing to obligate a TP/PC to officially notify them.

Likes 0

Dislikes 0

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer Yes

Document Name

Comment

Entergy has a concern regarding Medium Impact Rating Criterion 2.3. This Criterion calls for designating and informing respective Generator Owner or Generator Operator, each generation facility that its Planning Coordinator or Transmission Planner determines as necessary to avoid an Adverse

Reliability Impact in the planning horizon of more than one year. The concern here is there is no clarity in the roles of Planning Coordinator versus the Transmission Planner. The guidelines and technical basis section spells (page 29 of proposed clean version of the standard) out that in cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation. However, in cases where there is a Planning coordinator, the criterion or guideline does not spell out who is responsible. Secondly, this Criterion is far away from the "bright-line" intent of Attachment 1 Criteria in this standard. The Responsible entities have to perform several system studies to address the requirements to meet this criterion. Suggest the Standards Drafting Team consider spelling out what an entity should do incase they are registered with a Planning Coordinator.

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Matthew Goldberg - ISO New England, Inc. - 2 - NPCC

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer

Document Name [CIP-002-6 Comments.docx](#)

Comment

Additional comments: see attachment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI supports the comments provided by NRECA.

Likes 0

Dislikes 0

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer

Document Name

Comment

ABSTAIN with no comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

We concur that the modification provides some flexibility; however, there is no information/evidence to support any statement on cost-effectiveness and would recommend that NERC delete "in a cost effective manner."

Likes 0

Dislikes 0

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer

Document Name

Comment

No response.

Likes 0

Dislikes 0

Response

Standards Announcement

Reminder

Project 2016-02 Modifications to CIP Standards

Initial Ballots and Non-binding Polls Open through October 9, 2018

[Now Available](#)

The initial ballots and non-binding polls for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** and **CIP-003-8 - Cyber Security – Security Management Controls** are open through **8 p.m. Eastern, Tuesday, October 9, 2018.**

Balloting

Members of the ballot pools associated with this project can log in to the [Standards Balloting and Commenting System \(SBS\)](#) and submit their votes. If you experience difficulty navigating the SBS, contact [Wendy Muller](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through **October 9, 2018**

Ballot Pools Forming through **September 21, 2018**

[Now Available](#)

A 45-day formal comment period for **C CIP-002-6 - Cyber Security – BES Cyber System Categorization** and **CIP-003-8 - Cyber Security – Security Management Controls** is open through **8 p.m. Eastern, Tuesday, October 9, 2018**.

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. If you experience difficulty using the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, September 21, 2018**. Registered Ballot Body members can join the ballot pools [here](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 28 – October 9, 2018**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Comment: [View Comment Results](#)

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 Draft 1 IN 1 ST

Voting Start Date: 9/28/2018 12:01:00 AM

Voting End Date: 10/9/2018 8:00:00 PM

Ballot Type: ST

Ballot Activity: IN

Ballot Series: 1

Total # Votes: 257

Total Ballot Pool: 325

Quorum: 79.08

Weighted Segment Value: 55.89

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	33	0.508	32	0.492	0	5	19
Segment: 2	6	0.2	1	0.1	1	0.1	0	1	3
Segment: 3	75	1	26	0.491	27	0.509	0	5	17
Segment: 4	20	1	7	0.467	8	0.533	0	0	5
Segment: 5	73	1	28	0.5	28	0.5	0	4	13
Segment: 6	51	1	20	0.5	20	0.5	0	1	10
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	325	6.2	124	3.465	117	2.735	0	16	68

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
6	Basin Electric Power Cooperative	Jerry Horner		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments

5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
5	Exelon	Cynthia Lee		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
5	Entergy	Jamie Prater		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
4	City of Poplar Bluff	Neal Williams		None	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	None	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A

10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
3	Rutherford EMC	Tom Haire		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
6	Entergy	Julie Hall		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party

				Comments
1	City Utilities of Springfield, Missouri	Michael Buyce	None	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray	None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay	Affirmative	N/A
8	David Kiguel	David Kiguel	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway	None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Negative	Comments Submitted
5	Great River Energy	Preston Walsh	Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Julie Severino	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative N/A
3	Avista - Avista Corporation	Scott Kinney	Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Jeff Johnson	Affirmative N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative Comments Submitted
3	New York Power Authority	David Rivera	Negative	Comments Submitted
6	New York Power Authority	Thomas Savin	Negative	Comments Submitted
6	Duke Energy	Greg Cecil	Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry	Negative	Third-Party Comments
1	Peak Reliability	Scott Downey	Affirmative	N/A
1	Great River Energy	Gordon Pietsch	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason	None	N/A
1	Black Hills Corporation	Wes Wingen	None	N/A

Third-Party

3	Intermountain REA	David Maier		Negative	Comments
1	Portland General Electric Co.	Angela Gaines		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
5	Black Hills Corporation	George Tatar		Negative	Third-Party Comments
3	Public Utility District No. 1 of Pend Oreille County	Amber Orr		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A

5	Portland General Electric Co.	Ryan Olson		None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur	Joe Tarantino	Affirmative	N/A

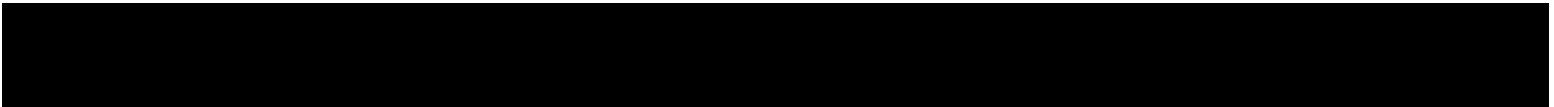
		Starkovich			
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike O'Neil		Affirmative	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allele - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
3	Lakeland Electric	Patricia Boody		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A

1	Sunflower Electric Power Corporation	Paul Mehlhaff	Affirmative	N/A
5	Austin Energy	Lisa Martin	None	N/A
6	Seattle City Light	Charles Freeman	Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer	Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao Helen Zhao	Affirmative	N/A
4	National Rural Electric Cooperative Association	Barry Lawson	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	None	N/A
6	Austin Energy	Andrew Gallo	None	N/A
4	Austin Energy	Jun Hua	None	N/A
3	City of Farmington	Linda Jacobson-Quinn	Affirmative	N/A
1	Seattle City Light	Pawel Krupa	None	N/A
4	City Utilities of Springfield, Missouri	John Allen	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	James Anderson	Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	None	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Negative	Comments Submitted
5	New York Power Authority	Shivaz Chopra	Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Negative	Third-Party Comments

6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	None	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Negative	Third-Party Comments
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge	Negative	Third-Party Comments
6	Black Hills Corporation	Eric Scherr	Negative	Third-Party Comments
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	None	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer	None	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Third-Party Comments
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Abstain	N/A
4	Arkansas Electric Cooperative Corporation	Alice Wright	Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Thomas Breene	Negative	Third-Party Comments
5	WEC Energy Group, Inc.	Linda Horn	Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano	Negative	Third-Party Comments
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley	None	N/A

6	WEC Energy Group, Inc.	David Hathaway	Negative	Third-Party Comments	
3	Seminole Electric Cooperative, Inc.	James Frauen	Affirmative	N/A	
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Affirmative	N/A	
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A	
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A	
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A	
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A	
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A	
3	Manitoba Hydro	Karim Abdel-Hadi	None	N/A	
1	Avista - Avista Corporation	Mike Magruder	None	N/A	
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Negative	Third-Party Comments	
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard	Abstain	N/A	
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter	None	N/A	
5	Arkansas Electric Cooperative Corporation	Moses Harris	Negative	Third-Party Comments	
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A	
5	National Grid USA	Elizabeth Spivak	Affirmative	N/A	
1	Los Angeles Department of Water and Power	faranak sarbaz	None	N/A	
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A	
3	National Grid USA	Brian Shanahan	None	N/A	
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Abstain	N/A	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A	
5	Los Angeles Department of Water and Power	Glenn Barry	None	N/A	
3	Eversource Energy	Sharon Flannery	Affirmative	N/A	
6	Manitoba Hydro	Blair Mukanik	None	N/A	
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A	
3	Empire District Electric Co.	Kalem Long	None	N/A	
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Negative	Comments Submitted	
3	JEA	Garry Baker	None	N/A	
1	Unisource - Tucson Electric Power Co.	John Tolo	None	N/A	
5	Seattle City Light	Faz Kasraie	None	N/A	
5	SunPower	Bradley Collard	None	N/A	
3	Southern Indiana Gas and Electric Co.	Ryan Abshier	None	N/A	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	Comments Submitted Third-Party	

1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
5	Hydro-Quebec Production	Carl Pineault		None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Negative	Comments Submitted
1	NB Power Corporation	Randy MacDonald		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	KAMO Electric Cooperative	Tony Gott		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A



[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 NBP IN 1 NB

Voting Start Date: 9/28/2018 12:01:00 AM

Voting End Date: 10/10/2018 8:00:00 PM

Ballot Type: NB

Ballot Activity: IN

Ballot Series: 1

Total # Votes: 241

Total Ballot Pool: 306

Quorum: 78.76

Weighted Segment Value: 51.55

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	23	0.46	27	0.54	15	20
Segment: 2	6	0.1	1	0.1	0	0	2	3
Segment: 3	69	1	25	0.521	23	0.479	10	11
Segment: 4	19	1	8	0.727	3	0.273	2	6
Segment: 5	69	1	21	0.488	22	0.512	10	16
Segment: 6	47	1	13	0.419	18	0.581	8	8
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment:	7	0.7	6	0.6	1	0.1	0	0
10								
Totals:	306	6.1	100	3.616	94	2.484	47	65

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted

3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
5	Exelon	Cynthia Lee		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
5	Entergy	Jamie Prater		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A

1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Jeff Johnson	Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	None	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
6	New York Power Authority	Thomas Savin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Peak Reliability	Michael Granath		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
					Comments

1	Lakeland Electric	Larry Watt		Negative	Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
3	Public Utility District No. 1 of Pend Oreille County	Amber Orr		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments

					Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
5	JEA	John Babik		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike O'Neil		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted

5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhane		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Lisa Martin		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		None	N/A
6	Austin Energy	Andrew Gallo		None	N/A
4	Austin Energy	Jun Hua		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	James Anderson		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire		Affirmative	N/A

4	CMS Energy - Consumers Energy Company	Theresa Martinez	Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Abstain	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Negative	Comments Submitted
5	New York Power Authority	Shivaz Chopra	Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	doug white	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	None	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge	Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr	Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	None	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck	Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer	None	N/A
3	Lakeland Electric	Patricia Boody	Negative	Comments

				Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Alice Wright	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
5	Arkansas Electric Cooperative Corporation	Adrian Harris	None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen	Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi	None	N/A
5	Brookfield Renewable Energy Partners - Brookfield Power Corporation	Robert Ricketts	None	N/A
1	Avista - Avista Corporation	Mike Magruder	None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard	Abstain	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative
				Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter	None	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	None	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
3	National Grid USA	Brian Shanahan	None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
3	Eversource Energy	Sharon Flannery	Affirmative	N/A

6	Manitoba Hydro	Blair Mukanik		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	JEA	Garry Baker		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
5	Seattle City Light	Faz Kasraie		None	N/A
5	SunPower	Bradley Collard		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Negative	Comments Submitted
1	NB Power Corporation	Nurul Abser		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	Omaha Public Power District	Aaron Smith		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A

Unofficial Nomination Form

Project Number 2016-02 Modifications to CIP Standards

Do not use this form for submitting nominations. Use the [electronic form](#) to submit nominations by **8 p.m. Eastern, Friday, March 29, 2019**. This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information can be found on the [Project 2016-02 Modifications to the CIP Standards](#) page. If you have questions, contact [Jordan Mallory](#) (via email), or at 404-446-2589.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2016-02 Modifications to CIP Standards

This solicitation for nominations is to augment the existing Project 2016-02 Modifications to CIP Standards drafting team that is continuing to address the Standard Authorization Request. NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas, but are not limited to:

- Virtualization;
- Cooperative representation;
- Canadian representation; and
- Guidelines and Technical Basis representation.

Standards Affected

CIP-002-6, CIP-003-7, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, and CIP-012-1.

The time commitment for this project is expected to be up to four face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Name:		
Organization:		
Address:		
Telephone:		
E-mail:		
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):		
<p>If you are currently a member of any NERC drafting team(s), please list each one here:</p> <input type="checkbox"/> Not currently on any active SAR or standard drafting team. <input type="checkbox"/> Currently a member of the following SAR or standard drafting team(s):		
<p>If you previously worked on any NERC drafting team(s), please identify each one here:</p> <input type="checkbox"/> No prior NERC SAR or standard drafting team. <input type="checkbox"/> Prior experience on the following team(s):		
<p>Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:</p>		
<input type="checkbox"/> Texas RE <input type="checkbox"/> FRCC <input type="checkbox"/> MRO	<input type="checkbox"/> NPCC <input type="checkbox"/> RF <input type="checkbox"/> SERC	<input type="checkbox"/> WECC <input type="checkbox"/> NA – Not Applicable

Select each Industry Segment that you represent:

- | | |
|--------------------------|--|
| <input type="checkbox"/> | 1 — Transmission Owners |
| <input type="checkbox"/> | 2 — RTOs, ISOs |
| <input type="checkbox"/> | 3 — Load-serving Entities |
| <input type="checkbox"/> | 4 — Transmission-dependent Utilities |
| <input type="checkbox"/> | 5 — Electric Generators |
| <input type="checkbox"/> | 6 — Electricity Brokers, Aggregators, and Marketers |
| <input type="checkbox"/> | 7 — Large Electricity End Users |
| <input type="checkbox"/> | 8 — Small Electricity End Users |
| <input type="checkbox"/> | 9 — Federal, State, and Provincial Regulatory or other Government Entities |
| <input type="checkbox"/> | 10 — Regional Reliability Organizations and Regional Entities |
| <input type="checkbox"/> | NA — Not Applicable |

Select each Function¹ in which you have current or prior expertise:

- | | |
|---|--|
| <input type="checkbox"/> Balancing Authority | <input type="checkbox"/> Transmission Operator |
| <input type="checkbox"/> Compliance Enforcement Authority | <input type="checkbox"/> Transmission Owner |
| <input type="checkbox"/> Distribution Provider | <input type="checkbox"/> Transmission Planner |
| <input type="checkbox"/> Generator Operator | <input type="checkbox"/> Transmission Service Provider |
| <input type="checkbox"/> Generator Owner | <input type="checkbox"/> Purchasing-selling Entity |
| <input type="checkbox"/> Interchange Authority | <input type="checkbox"/> Reliability Coordinator |
| <input type="checkbox"/> Load-serving Entity | <input type="checkbox"/> Reliability Assurer |
| <input type="checkbox"/> Market Operator | <input type="checkbox"/> Resource Planner |
| <input type="checkbox"/> Planning Coordinator | |

¹ These functions are defined in the NERC [Functional Model](#), which is available on the NERC web site.

Provide the names and contact information of two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.

Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Nomination Period Open through March 29, 2019

[Now Available](#)

Nominations are being sought for standard drafting team members through **8 p.m. Eastern, Friday, March 29, 2019.**

Use the [electronic form](#) to submit a nomination. If you experience difficulties using the electronic form, contact [Wendy Muller](#). An unofficial Word version of the nomination form is posted on the [Standard Drafting Team Vacancies](#) and the [project page](#).

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2016-02 Modifications to CIP Standards

This solicitation for nominations is to augment the existing Project 2016-02 Modifications to CIP Standards drafting team that is continuing to address the Standard Authorization Request. NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas, but are not limited to:

- Virtualization;
- Cooperative representation;
- Canadian representation; and
- Guidelines and Technical Basis representation.

Standards Affected

CIP-002-6, CIP-003-7, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, and CIP-012-1.

The time commitment for this project is expected to be up to four face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Next Steps

The Standards Committee is expected to appoint members to the team in April 2019. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	June 3 – July 18, 2019

Anticipated Actions	Date
10-day final ballot	July 24 – August 2, 2019
NERC Board	August 15, 2019

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation., of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

- 4.1.3. **Generator Operator**
- 4.1.4. **Generator Owner**
- 4.1.5. **Reliability Coordinator**
- 4.1.6. **Transmission Operator**
- 4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. **Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers:** All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See Implementation Plan for CIP-002-6

- 5.1. **Planned and Unplanned Changes:** If a Responsible Entity has a planned change¹ or unplanned change,² the Responsible Entity shall comply with the requirements in this Reliability Standard as follows:

For a planned change resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.

For a planned change resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2, Part 2.1. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the existing BES Cyber System.

¹ **Planned changes** are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity's advance knowledge. Planned changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen by the Responsible Entity. Examples of planned changes include, but are not limited to: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² **Unplanned changes** refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity's advance knowledge or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of unplanned changes include, but are not limited to: (1) a Responsible Entity is notified (internally or externally) that a generation Facility has been designated per CIP-002, Attachment 1, Criterion 2.3; (2) a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per CIP-002, Attachment 1, Criterion 2.6; (3) a generating resource that is connected at less than 100kV is designated per CIP-002, Attachment 1, Criterion 3.4; or (4) a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in CIP-002, Attachment 1, Criterion 2.10.

For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective 24 calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until 24 calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following a planned change shall occur within the first period following the date the new BES Cyber System could adversely impact the BES or the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period after 24 calendar months from the date of notification or detection of the unplanned change.

6. Background:

This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

The term “BES Cyber System” provides a convenient level at which a Responsible Entity can organize its documented implementation of the requirements and compliance evidence. Responsible Entities can use a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the characteristics in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a more precise time horizon than “Real-time,” BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.6 Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8 Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9 Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10 Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry’s overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

- 2.12** Control Centers or backup Control Centers not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13 Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities,” there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as, “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with

equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to

remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been

included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in Attachment 1 of NERC's "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)" document, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. ∴ there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or

Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

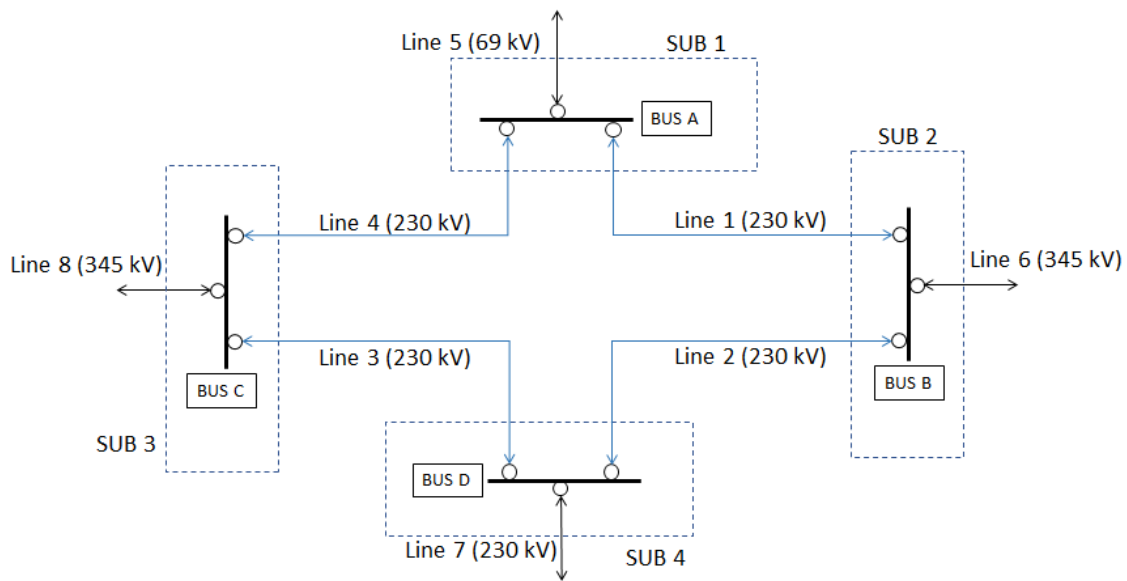
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

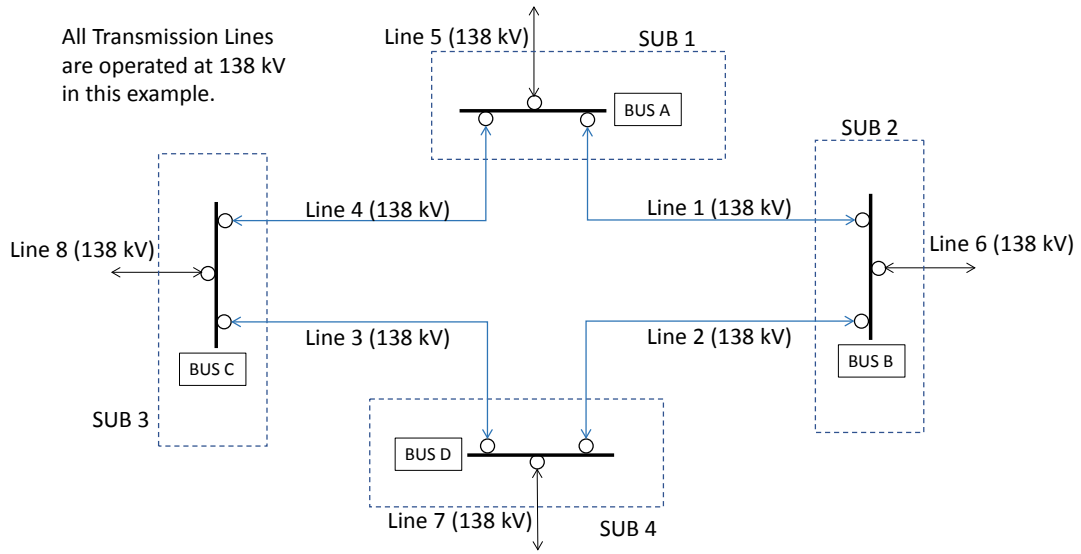
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

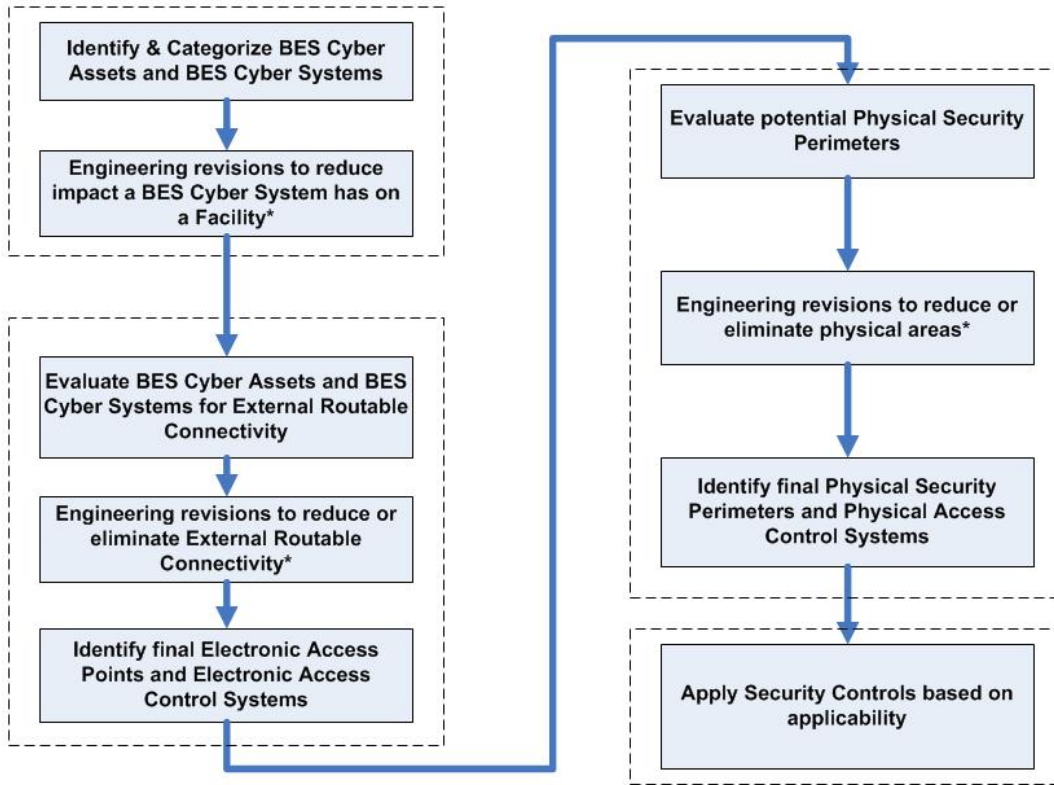
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard.

<u>Completed Actions</u>	<u>Date</u>
<u>Standards Committee approved Standard Authorization Request (SAR) for posting</u>	<u>March 9, 2016</u>
<u>SAR posted for comment</u>	<u>March 23 - April 21, 2016</u>
<u>SAR posted for comment</u>	<u>June 1 – June 30, 2016</u>
<u>Informal comment period</u>	<u>March 14, 2017 – April 11, 2017</u>
<u>45-day formal comment period with initial ballot</u>	<u>September 14 – October 30, 2017</u>
<u>45-day formal comment period with additional ballot</u>	<u>March 16 – April 30, 2018</u>
<u>45-day formal comment period with additional ballot</u>	<u>June 3 – July 18, 2019</u>

<u>Anticipated Actions</u>	<u>Date</u>
<u>10-day final ballot</u>	<u>July 24 – August 2, 2019</u>
<u>NERC Board</u>	<u>August 15, 2019</u>

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-~~5.1a6~~
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** -For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” -For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~4.1.5. Interchange Coordinator or Interchange Authority~~

~~4.1.6.4.1.5. Reliability Coordinator~~

~~4.1.7.4.1.6. Transmission Operator~~

~~4.1.8.4.1.7. Transmission Owner~~

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers:** All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-6:

- 4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See Implementation Plan for CIP-002-6

5.1. Planned and Unplanned Changes: If a Responsible Entity has a planned change¹ or unplanned change,² the Responsible Entity shall comply with the requirements in this Reliability Standard as follows:

For a planned change resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.

¹ Planned changes are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or with the Responsible Entity's advance knowledge. Planned changes typically involve a change to a Bulk Electric System asset (e.g., substation, generating resource, Control Center) or a change to a Cyber Asset that was foreseen by the Responsible Entity. Examples of planned changes include, but are not limited to: (1) placing a new transmission substation into service or adding a new line to an existing substation; (2) placing a new BES generation resource into service or adding a generation resource to an existing plant; (3) placing a new primary or backup Control Center or associated data center into service or implementing a new supervisory control and data acquisition (SCADA) system or energy management system (EMS) or an upgrade to an existing SCADA system or EMS; (4) implementing a project for substation automation where Cyber Assets are installed, upgraded, or replaced such as electromechanical relays being replaced with digital relays; or (5) implementing a control system upgrade at a generating resource.

² Unplanned changes refer to (i) any changes to the Bulk Electric System or a Cyber Asset that occur without the entity's advance knowledge or (ii) changes to the categorization of a Cyber Asset caused by a notification from another entity or the output of a planning study. Examples of unplanned changes include, but are not limited to: (1) a Responsible Entity is notified (internally or externally) that a generation Facility has been designated per CIP-002, Attachment 1, Criterion 2.3; (2) a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per CIP-002, Attachment 1, Criterion 2.6; (3) a generating resource that is connected at less than 100kV is designated per CIP-002, Attachment 1, Criterion 3.4; or (4) a system study that shows changes in customer load have resulted in crossing the 300 MW threshold of a load shedding system as described in CIP-002, Attachment 1, Criterion 2.10.

For a planned change resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2, Part 2.1. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the existing BES Cyber System.

For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective 24 calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until 24 calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following a planned change shall occur within the first period following the date the new BES Cyber System could adversely impact the BES or the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period after 24 calendar months from the date of notification or detection of the unplanned change.

~~1. **24 Months Minimum** — CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

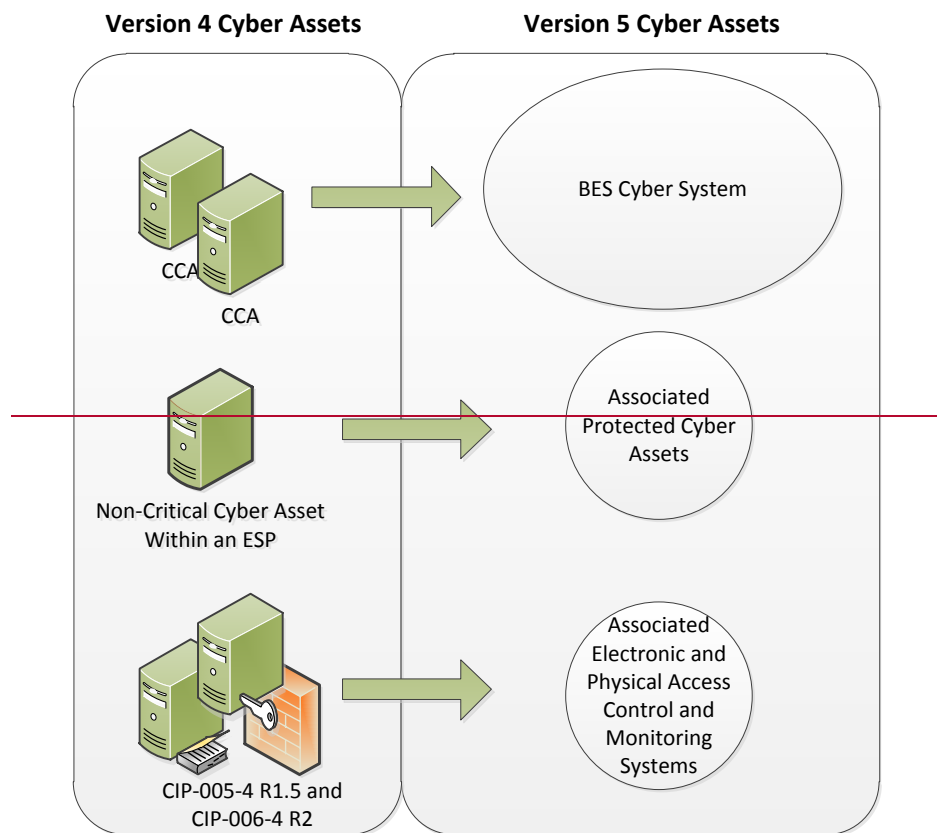
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the~~The term “BES Cyber System” ~~is to provide~~s a convenient level at which a Responsible Entity can organize ~~its~~their documented implementation of the requirements and ~~its examples of~~ compliance evidence. Responsible Entities can use ~~a the well-developed concept of a~~ security plan for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the characteristics in the definition of BES Cyber System. -For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. -The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. -Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. -This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. -The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. -The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these ~~Version 5~~-CIP Cyber Security Standards is defined as that

which is material to real-time operations for the reliable operation of the BES. -To provide a ~~more precisely better defined~~ time horizon than “Real-time,” BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. -This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. -Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. -All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, ~~Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11~~ Section 1 or Section 2, and listed in Section 3 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the ~~Version 5~~ CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples ~~may~~ include, to the extent they are within the ESP: -file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *-[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 -high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 -high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

~~None.~~

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

~~CIP-002-5.1a-~~

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>1</u>	<u>1/16/06</u>	<u>R3.2 — Change “Control Center” to “control center.”</u>	<u>3/24/06</u>
<u>2</u>	<u>9/30/09</u>	<p><u>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</u></p> <p><u>Removal of reasonable business judgment.</u></p> <p><u>Replaced the RRO with the RE as a Responsible Entity.</u></p> <p><u>Rewording of Effective Date.</u></p> <p><u>Changed compliance monitor to Compliance Enforcement Authority.</u></p>	
<u>3</u>	<u>12/16/09</u>	<p><u>Updated version number from -2 to -3.</u></p> <p><u>Approved by the NERC Board of Trustees.</u></p>	<u>Update</u>
<u>3</u>	<u>3/31/10</u>	<u>Approved by FERC.</u>	
<u>4</u>	<u>12/30/10</u>	<u>Modified to add specific criteria for Critical Asset identification.</u>	<u>Update</u>
<u>4</u>	<u>1/24/11</u>	<u>Approved by the NERC Board of Trustees.</u>	<u>Update</u>
<u>5</u>	<u>11/26/12</u>	<u>Adopted by the NERC Board Trustees.</u>	<p><u>Modified to coordinate with other CIP standards and to revise format to use RBS Template.</u></p>

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>5.1</u>	<u>9/30/13</u>	<u>Replaced “Devices” with “Systems” in a definition in background section.</u>	<u>Errata</u>
<u>5.1</u>	<u>11/22/13</u>	<u>FERC Order issued approving CIP-002-5.1.</u>	
<u>5.1a</u>	<u>11/02/16</u>	<u>Adopted by the NERC Board of Trustees.</u>	
<u>5.1a</u>	<u>12/14/2016</u>	<u>FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.</u>	
<u>6</u>	<u>TBD</u>		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating ~~(H)~~

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4** Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9** Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11** Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- ~~**2.12** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry’s overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document³ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

Due to the ongoing confusion of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

³ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

2.12 Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

2.13 Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating ~~(L)~~

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-~~5.1a6~~ and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-~~5.1a6~~. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-~~5.1a6~~

CIP-002-~~5.1a6~~ requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. -The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-~~5.1a-6~~. The concept includes a number of named BES reliability operating services. ~~These named services include:~~

These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. -Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. -The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. -These actions are triggered by a single element or control device or a combination of these elements

or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. -The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. -Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding

- Ability to identify load change need (BA)
- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. -Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. -Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. -Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. -Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. -Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)

- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. -Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. -Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. -The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. -Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. -BES Cyber Systems for BES assets not specified in Attachment 1, Criteria, [Section 1 or Section 2, and listed in Section 3-1.1 – 1.4 and Criteria 2.1 – 2.11](#) default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities,” there is some latitude to Responsible Entities to determine included Facilities. -The term Facility is defined in the NERC Glossary of

Terms as, “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” -In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities.- However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. -In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. -Generation Facilities are separately discussed in the Generation section below. In CIP-002-~~5.1a6~~, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria.- In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. -This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating ~~(H)~~

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. -While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). -In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. -The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, ~~BA~~s, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities

that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of ~~Bas~~BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating ~~(M)~~

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. -Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. -The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." -In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." -The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or

Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a “long term” reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. -In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. -Those units designated as must run for voltage support in the local area would not generally be given this designation. -In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators

which own BES Cyber Systems for such Systems and schemes designate them as medium impact.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. -Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. -Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). -Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. -The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. -The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. -While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. -While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. -The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. -The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in [Attachment 1 of NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index" document, Attachment 1](#), the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. -In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. -In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate connections to other stations. -The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. -In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. -Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would

contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. -Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. ∴ there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation

owner as to the qualification of generation Facilities connected to their Transmission systems.

- Criterion 2.9 designates as medium impact those BES Cyber Systems ~~for those Special Protection Systems (SPS), Remedial Action Schemes (RAS),~~ or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. -By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. -The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. -In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. -It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. -The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1.- The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a, that monitor and control BES Transmission Operator Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

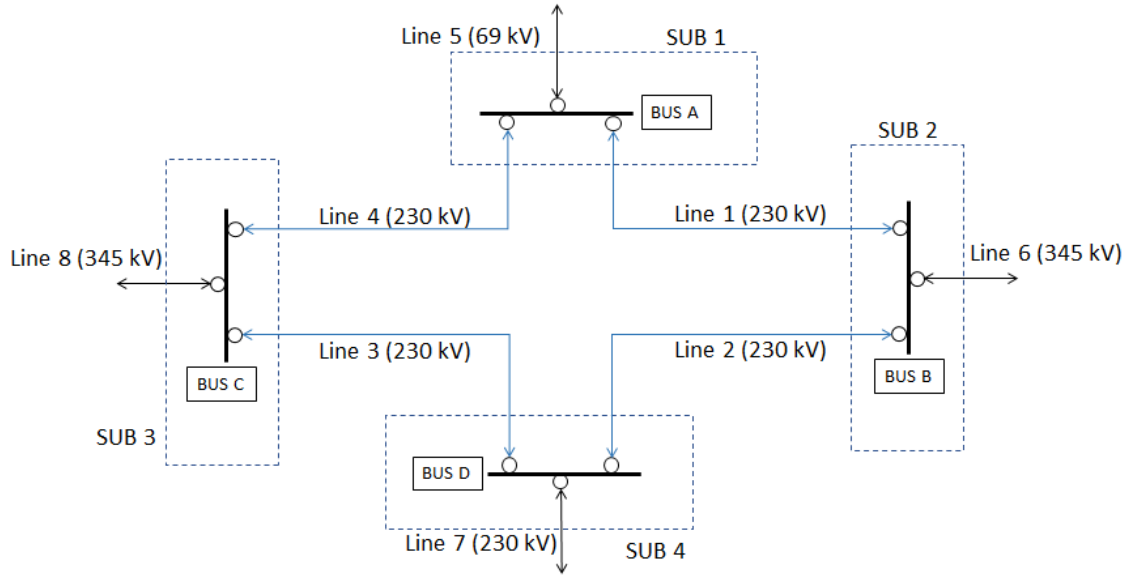
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

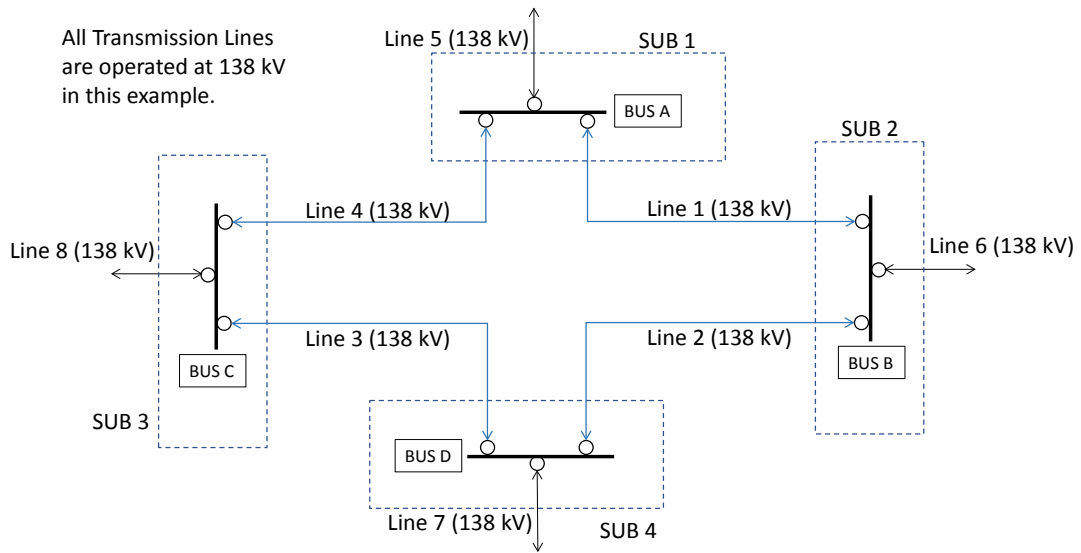
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>Line 5</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>None</u>	<u>0</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 7</u>	<u>3500</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>Line 6, Line 8</u>	<u>2600</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as high impact, a low impact BES Cyber System(s) pursuant to Criterion 3.1.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>None</u>	<u>N/A</u>

<u>100 kV to 199 kV</u>	<u>250</u>	<u>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</u>	<u>2000</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>None</u>	<u>0</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>None</u>	<u>0</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs.- For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.-

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. -This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to

restoration assets are included in those versions).- Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response.- This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability.- Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. -This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. -The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

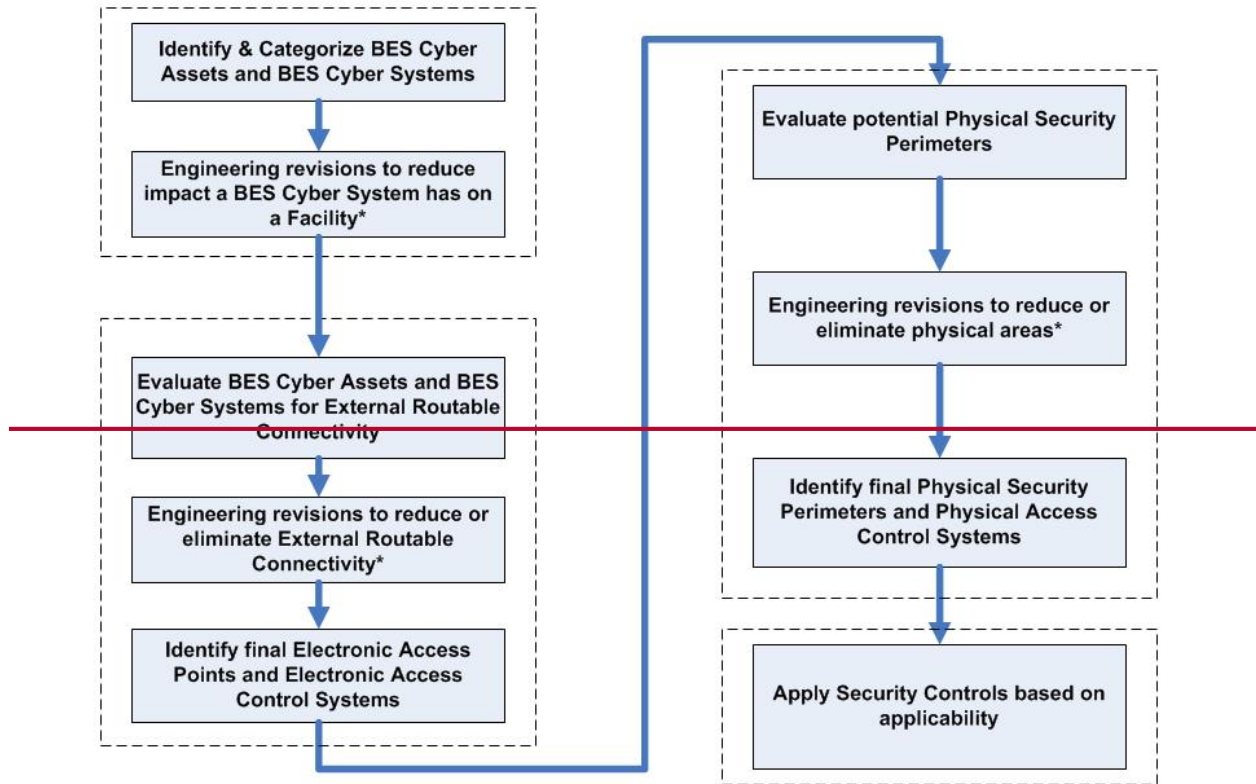
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

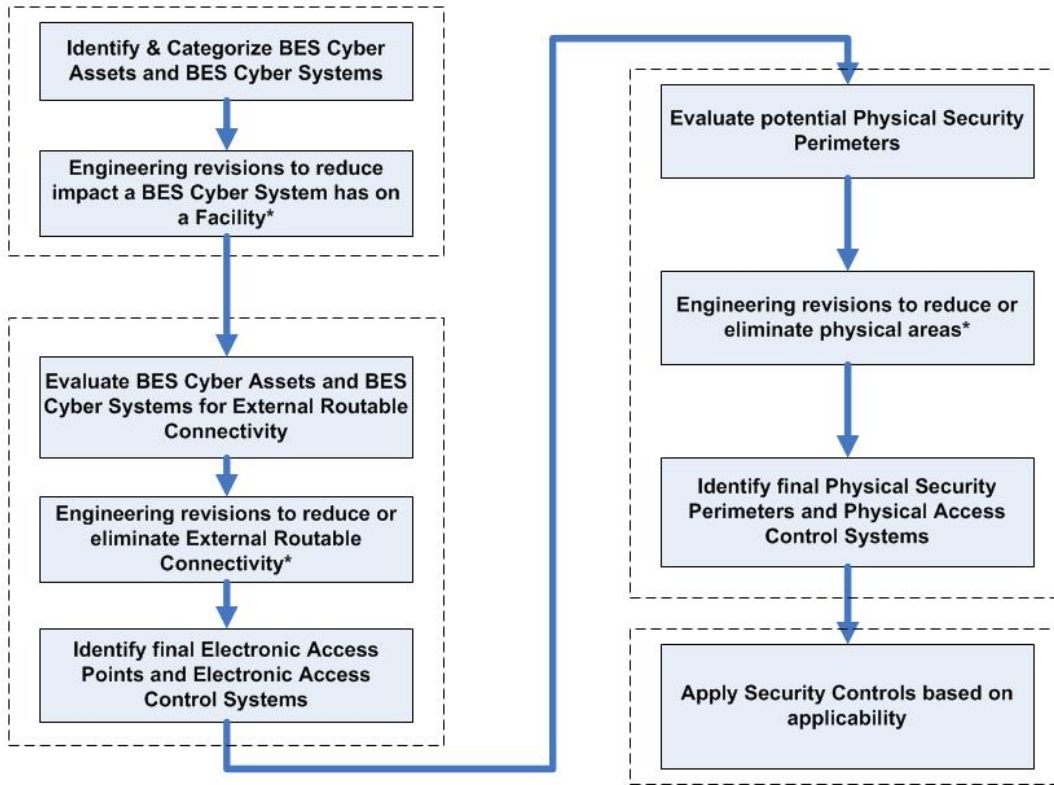
The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale[†]

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. -Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. —These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. -The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. -The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from 2 to 3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	

Guidelines and Technical Basis

5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
------	-----------------------	---	--

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization

Prerequisite Standard(s) or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

This Implementation Plan includes a phased-in implementation date for Criterion 2.12 in CIP-002-6, Attachment 1. This allows Responsible Entities¹ a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System. The phased-in implementation date is only for changes resulting from the revisions to Criterion 2.12; other changes in impact level for BES Cyber Systems are covered in Section 5.1 planned and unplanned changes in CIP-002-6.

¹ As used in the CIP Reliability Standards, a Responsible Entity refers to registered functions listed under Applicable Entities.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

Any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards

CIP-002-6

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments on **CIP-002-6 - Cyber Security – BES Cyber System Categorization**. Comments must be submitted by **8 p.m. Eastern, Wednesday, July 17, 2019**.

Additional information is available on the [project page](#). If you have questions, contact Standards Developer, [Jordan Mallory](#) (404-446-2589).

Background Information

Project 2016-02 was formed to (1) address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822 and (2) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document).

The V5TAG, which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP Version 5 standards and to support industry's implementation activities. During the V5TAG's activities, it identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the [CIP Version 5 Transition Advisory Group Issues for Consideration](#) document to formally recommend that the SDT address these issues and consider modifications to the standard language during the standards development process. Among other issues of the V5TAG recommended clarification of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12. The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12. The aggregate weighted value is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the BES Cyber System(s) exceeds the 6000 aggregate weighted value, it should be identified as a medium impact BES Cyber System. If the BES Cyber System does not exceed the 6000 aggregate weighted value, it should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

These changes were posted and balloted (93% approval) by industry in April, 2018. Since that time, other changes have been incorporated into CIP-002-6. The proposed CIP-002-6 also includes new clarifying language in the Effective Date section of the standard that addresses the compliance date for

BES Cyber Systems whose impact categorization changes due to Bulk Electric System changes. These changes fall into either planned or unplanned change categories.

A version of CIP-002-6 was posted for ballot September 28 through October 9, 2018 that included modifications to criteria 2.6 and 2.9 based on the work of the Project 2015-09 – Establish and Communicate System Operating Limits standard drafting team. The Project 2016-02 and Project 2015-09 standard drafting teams determined that these revisions are no longer needed at this time. As a result, CIP-002-6 will be posted for an additional comment and ballot period without these revisions to criteria 2.6 and 2.9. NERC will reopen the ballot pool to accommodate changes in the ballot body.

Questions

1. Attachment 1, Criterion 2.12: No changes have been added from the April 2018 ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

2. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

3. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the responsible entity performs its review of identifications under Requirement R2, Part 2.1. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

4. Effective Date Section: Do you agree with the proposed modification to the unplanned changes section that provides 24 months for implementation of the requirements? If yes, please provide comments on why the timeframe is appropriate to assist the SDT with additional justification. If no, please provide your rationale and an alternate proposal.

- Yes
- No

Comments:

5. Implementation Plan: The SDT modified the Implementation Plan. Do you agree with the proposed Implementation Plan?
- a. If yes, please provide comments on why the timeframes are appropriate to assist the SDT with additional justification.
 - b. If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

- Yes
- No

Comments:

6. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

- Yes
- No

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

Justification for VRFs and VSLs

- Requirement R1: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.
- Requirement R2: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.

Reliability Standard Audit Worksheet¹

CIP-002-6 – Cyber Security – BES Cyber System Categorization

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X	*	X	X		X			X	X		
R2	X	*	X	X		X			X	X		

*CIP-002-6 is only applicable to DPs that own certain UFLS, UVLS, RAS, Protection Systems, or Cranking Paths. See CIP-002-6 Section 4, Applicability, for details.

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

DRAFT NERC Reliability Standard Audit Worksheet

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

DRAFT NERC Reliability Standard Audit Worksheet

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i.** Control Centers and backup Control Centers;
 - ii.** Transmission stations and substations;
 - iii.** Generation resources;
 - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

Registered Entity Response (Required):

Question 1: Do you share compliance responsibility for this Requirement with another Responsible Entity?

Yes No

For example, is any BES Cyber System located at a shared facility?

If “Yes,” list the following for each asset for which compliance responsibility is shared:

- 1. Asset name or designation.
- 2. Formal agreement or other document describing the shared compliance responsibility, if any.
- 3. Other information regarding the shared compliance responsibility which may be useful to the audit team in determining the appropriate audit scope and approach for the asset.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-6, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the Responsible Entity has a process to identify each high impact BES Cyber System, each medium impact BES Cyber System, and each asset that contains a low impact BES Cyber System.
	Verify the above process considers all of the following: <ul style="list-style-type: none"> i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 of the Standard.
	Verify the Responsible Entity has identified each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset.
	Verify the Responsible Entity has identified each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset.
	Verify the Responsible Entity has identified each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any.

Auditor Notes:

R2 Supporting Evidence and Documentation

- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-6, R2

This section to be completed by the Compliance Enforcement Authority

	Verify the reviews of the identifications in Requirement R1 have occurred at least once every 15 calendar months.
	Verify the approvals by the CIP Senior Manager or delegate of the identifications in Requirement R1 have occurred at least once every 15 calendar months.

Auditor Notes:

DRAFT

Additional Information:

Reliability Standard

The full text of CIP-002-6 may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Standards”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

FERC Order No. 706

FERC Order No. 791

FERC Letter Order dated December 27, 2016, Docket No. RD17-2-000

FERC Order No. TBD [Order approving CIP-002-6]

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3.** Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4.** Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5.** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7.** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8.** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9.** Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest

rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

- 2.12.** Control Centers or backup Control Centers not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

DRAFT NERC Reliability Standard Audit Worksheet

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	06/04/2019	RSAWTF	New Document
2	06/20/2019	WECC, TexasRE	Text changes to Applicability of Requirements, R1 Compliance Assessment Approach, M2, Attachment 1 to align with language of present draft Standard.

DRAFT

Reliability Standard Audit Worksheet¹

CIP-002-6 – Cyber Security – BES Cyber System Categorization

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X	*	X	X		X			X	X		
R2	X	*	X	X		X			X	X		

*CIP-002-6 is only applicable to DPs that own certain UFLS, UVLS, RAS, ~~protection systems~~Protection Systems, or ~~cranking paths~~Cranking Paths. See CIP-002-6 Section 4, Applicability, for details.

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

DRAFT NERC Reliability Standard Audit Worksheet

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

DRAFT NERC Reliability Standard Audit Worksheet

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*
- i.** Control Centers and backup Control Centers;
 - ii.** Transmission stations and substations;
 - iii.** Generation resources;
 - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

Registered Entity Response (Required):

Question 1: Do you share compliance responsibility for this Requirement with another Responsible Entity?

Yes No

For example, is any BES Cyber System located at a shared facility?

If “Yes,” list the following for each asset for which compliance responsibility is shared:

- 1. Asset name or designation.
- 2. Formal agreement or other document describing the shared compliance responsibility, if any.
- 3. Other information regarding the shared compliance responsibility which may be useful to the audit team in determining the appropriate audit scope and approach for the asset.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-6, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the Responsible Entity has a process to identify each high impact BES Cyber System, each medium impact BES Cyber System, and each asset that contains a low impact BES Cyber System.
	Verify the above process considers all of the following: <ul style="list-style-type: none"> i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 of the Standard.
	Verify the Responsible Entity has identified each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset.
	Verify the Responsible Entity has identified each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset.
	Verify the Responsible Entity has identified each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any.

Auditor Notes:

DRAFT NERC Reliability Standard Audit Worksheet

R2 Supporting Evidence and Documentation

- R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2. ~~dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.~~

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-002-6, R2

This section to be completed by the Compliance Enforcement Authority

	Verify the reviews of the identifications in Requirement R1 have occurred at least once every 15 calendar months.
	Verify the approvals by the CIP Senior Manager or delegate of the identifications in Requirement R1 have occurred at least once every 15 calendar months.

Auditor Notes:

DRAFT

Additional Information:

Reliability Standard

The full text of CIP-002-6 may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Standards”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

FERC Order No. 706

FERC Order No. 791

FERC Letter Order dated December 27, 2016, Docket No. RD17-2-000

FERC Order No. TBD [Order approving CIP-002-6]

Attachment 1 – Impact Rating Criteria~~CIP-002-6 – Attachment 4~~

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating ~~(H)~~

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

DRAFT NERC Reliability Standard Audit Worksheet

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load

shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Control Centers or backup Control Centers not included in High Impact Rating above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating ~~(L)~~

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

DRAFT NERC Reliability Standard Audit Worksheet

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	06/04/2019	RSAWTF	New Document
<u>2</u>	<u>06/20/2019</u>	<u>WECC, TexasRE</u>	<u>Text changes to Applicability of Requirements, R1 Compliance Assessment Approach, M2, Attachment 1 to align with language of present draft Standard.</u>

DRAFT

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through July 17, 2019

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Wednesday, July 17, 2019**.

A version of CIP-002-6 was posted for ballot September 28 through October 9, 2018, that included modifications to criteria 2.6 and 2.9 based on the work of the [Project 2015-09 Establish and Communicate System Operating Limits](#) standard drafting team. The Project 2016-02 Modifications to CIP Standards and Project 2015-09 standard drafting teams determined that these revisions are no longer needed at this time. As a result, CIP-002-6 will be posted for an additional comment and ballot period without the revisions to criteria 2.6 and 2.9. NERC will reopen the ballot pool to accommodate changes in the ballot body.

Ballot Pools

Registered Ballot Body members can join the ballot pools in the [Standards Balloting and Commenting System \(SBS\)](#) until **8 p.m. Eastern, Tuesday, July 2, 2019**.

Commenting

Use the [SBS](#) to submit comments. If you experience issues navigating the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 8-17, 2019**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards | CIP-002-6 (Draft 3)
Comment Period Start Date: 6/3/2019
Comment Period End Date: 7/17/2019
Associated Ballots: 2016-02 Modifications to CIP Standards CIP-002-6 AB 3 ST

There were 69 sets of responses, including comments from approximately 148 different people from approximately 107 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

- 1. Attachment 1, Criterion 2.12: No changes have been added from the April 2018 ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.**

- 2. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.**

- 3. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the responsible entity performs its review of identifications under Requirement R2, Part 2.1. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.**

- 4. Effective Date Section: Do you agree with the proposed modification to the unplanned changes section that provides 24 months for implementation of the requirements? If yes, please provide comments on why the timeframe is appropriate to assist the SDT with additional justification. If no, please provide your rationale and an alternate proposal.**

- 5. Implementation Plan: The SDT modified the Implementation Plan. Do you agree with the proposed Implementation Plan?**
 - a. If yes, please provide comments on why the timeframes are appropriate to assist the SDT with additional justification.**
 - b. If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.**

- 6. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	Tennessee Valley Authority	Kurtz, Bryan G.	Tennessee Valley Authority	1	SERC
					Grant, Ian S.	Tennessee Valley Authority	3	SERC
					Thomas, M. Lee	Tennessee Valley Authority	5	SERC
					Parsons, Marjorie S.	Tennessee Valley Authority	6	SERC
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Public Utility District No. 1 of Chelan County	Davis Jelusich	6		Public Utility District No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Jennifer Bray	Arizona Electric Power Cooperative	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Patrick Woods	East Kentucky Power Cooperative	1,3	SERC

					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					Carl Behnke	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	SERC
FirstEnergy - FirstEnergy Corporation	Julie Severino	1		FirstEnergy	Aubrey Short	FirstEnergy - FirstEnergy Corporation	4	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Duke Energy	Katherine Street	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
					Lee Schuster	Duke Energy	3	SERC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrienne Collins	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama	3	SERC

						Power Company		
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion annd Con Ed	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent	2	NPCC

						System Operator		
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					John Hastings	National Grid	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable

1. Attachment 1, Criterion 2.12: No changes have been added from the April 2018 ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Anthony Jablonski - ReliabilityFirst - 10

Answer No

Document Name

Comment

The proposed language will not reduce the confusion regarding the identification of medium impact BES Cyber Systems. Many entities in the RF footprint have Control Centers that monitor BES Transmission Lines but only control those lines under direction from the registered TOP. The language in this Draft of CIP-002-6 does not make clear that these entities must identify BES Cyber Systems in such Control Centers as medium impact. RF suggests changing the phrase "that monitor and control" to "that are capable of controlling or monitoring."

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer No

Document Name

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the following methodology:

BES Cyber Systems are to be rated as high, medium, or low impact as follows:

A high impact BES Cyber System is a Control Center that has one or more of the following characteristics:

1. Is used to operate transmission lines of 500kV or above;
2. Supports a sum greater than 2500kV of transmission lines above 230kV;
3. Supports generation with an aggregate capacity greater than 3000MW;
4. Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact.

A medium impact BES Cyber System has one or more of the following characteristics:

1. Supports generation with the aggregate capacity between 1500 – 3000MW;
2. Supports a sum between 1500 – 2500kV of transmission lines above 230kV;
3. Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more.

A low impact BES Cyber System has one or more of the following characteristics:

1. Supports a sum less than 1500kV of transmission lines above 230kV;
2. Supports transmission only between 100 – 230kV;
3. Supports generation with an aggregate capacity between 75 – 1500MW;
4. Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System;
5. Supports any Facilities that are designated a blackstart resource;
6. Supports any other RAS not already identified as a medium impact BES Cyber System.

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

No

Document Name

Comment

Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

No

Document Name

Comment

Texas RE appreciates the standard drafting team’s (SDT) work on revising this standard. Texas RE does have two concerns regarding Criterion 2.12. Primarily, Texas RE is concerned that the new Criterion 2.12 will result in some entities who were previously classified as medium impact to be classified as low impact, thus taking away the applicability of requirements CIP-003-CIP-011. Currently, under high impact rating 1.3, a Transmission Owner or Transmission Operator that owns Control Center(s) or backup Control Center(s) that is **not** used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 would **not** have identified high impact BES Cyber Systems. Under medium impact rating 2.12, however, those BES Cyber Systems would be identified as medium impact, which states, “2.12. *Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above*”.

The Texas RE region has several entities in its footprint that could potentially change from a medium impact to low impact, which could reduce reliability as they would not be obligated to comply with CIP-003-CIP-011. The following scenarios could take place as a result of the change.

Texas RE appreciates the standard drafting team's (SDT) work on revising this standard. Texas RE does have two concerns regarding Criterion 2.12. Primarily, Texas RE is concerned that the new Criterion 2.12 will result in some entities who were previously classified as medium impact to be classified as low impact, thus taking away the applicability of requirements CIP-003-CIP-011. Currently, under high impact rating 1.3, a Transmission Owner or Transmission Operator that owns Control Center(s) or backup Control Center(s) that is **not** used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 would **not** have identified high impact BES Cyber Systems. Under medium impact rating 2.12, however, those BES Cyber Systems would be identified as medium impact, which states, "2.12. *Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above*".

The Texas RE region has several entities in its footprint that could potentially change from a medium impact to low impact, which could reduce reliability as they would not be obligated to comply with CIP-003-CIP-011. The following scenarios could take place as a result of the change.

- Example #1: A **TO or TOP** that monitors and controls substation(s) that are operating **less than 200 kV** and not connected to three or more other Transmission stations or substations and **does not** have an "aggregate weighted value" exceeding 3000 (Criterion 2.5) would not have identified high impact BES Cyber Systems. However, the current language of Criterion 2.12 would identify those BES Cyber Systems as medium impact.
- Example #2: A **TO or TOP** that monitors and controls substation(s) that are operating **345 kV** and are connected to **one or two** other Transmission stations or substations and **does not** have an "aggregate weighted value" exceeding 3000 (Criterion 2.5) would not have identified high impact BES Cyber Systems. However, the current language of Criterion 2.12 would identify those BES Cyber Systems as medium impact.

With the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12 uses the "aggregate weighted value" exceeding 6000. In both scenarios above, the identified medium impact BES Cyber Systems *could* now be identified as low impact BES Cyber Systems if all the BES Transmission Lines did not have an **"aggregate weighted value" exceeding 6000**.

Secondly, Texas RE recommends adding a requirement that entities should consider the impact of locations where the impact of the sub-100 kV Transmission Line resulted in the inclusion of that line as a BES Transmission Line, since a sub-100kV system contributed to the September 2011 southwest blackout. In the aggregate weight table there is no provision for Transmission Lines below 100 kV that have been flagged as part of the weighting system.

Texas RE also noticed two additional items with regards to the standard. First, the rationale box for Criterion 2.12 states "The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV." This comment form, however, states "The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV." Texas RE inquires as to which is correct.

Lastly, Texas RE has the following additional comments regarding the Guidelines and Technical Basis:

- Texas RE is of the understanding that Guidelines and Technical Basis are being converted to Technical Rationale and/or Implementation Guidance in accordance with the Technical Rationale Transition Plan. Since CIP-002-6 is open for development, it seems that the SDT should be following Track 2 of the Transition Plan. It also appears that the content related to Criterion 2.12 should be considered for development as Implementation Guidance and should follow the Compliance Guidance Policy.
- Under "Generation" on page 29, "Bas" should be "BAs".

- On page 30, the second paragraph includes a reference to TPL-003, for which there is no currently effective version: “If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.” Texas RE recommends updating language to: “If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to an event identified in the TPL Standards, then BES Cyber Systems for that unit are categorized as medium impact.”
- On page 30, in the third paragraph, it states “The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.” This language is not used in TPL-001-4, but similar language addressing the use of non-consequential load loss is used in Footnote 12. Recommend updating this language to be consistent with the effective standards.
- On page 31, in the second bullet, “interconnection” should be capitalized as it is a defined term in the NERC Glossary.
- On page 31, under Transmission, the following statement appears to be out of date given the implementation of MOD-025-2: “Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities.” Texas RE recommends the SDT update that statement.
- On page 32 strike “Attachment 1 of” in the sentence starting with “Additionally...”. The link provided links to Attachment 1.
- On page 33, the second bullet from the bottom - The phrase “... and its Transmission provider” should be changed to “... and its Transmission Entity(ies)” as defined in NUC-001-3. In the last sentence on page 33, “Generation” should be lower case or changed from “Generation owner” to “Generator Owner”.
- On page 34, in the first full sentence, “for” should not be deleted after “BES Cyber Systems”.
- On page 34, in the third paragraph, there should be a space in “1500MW”.
- On page 34, the fourth paragraph references Load acting as a Resource (“LaaR”). Since LaaR does not exist anymore in the ERCOT region, Texas RE recommends updating this paragraph.
- On page 35, Texas RE requests the analysis and results of the analysis used by the SDT to validate that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk. There are 108 registered BAs, 19 RCs, and 181 TOPs that have Control Centers. GOPs and TOs acting as a TOP do not have clear numbers.
- Beginning on page 36, the Restoration Facilities section appears to have been written in 2012. Texas RE suggests the SDT review it and make necessary updates. For example, EOP-005-2 is no longer effective.

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer

Yes

Document Name

Comment

Black Hills agrees with the approach, but wonder if there might be inconsistency among entities in how BES Transmission Lines are counted, i.e. does segmentation of a transmission path increase the "number" of lines?

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

Yes

Document Name

Comment

NSRF appreciates the additional clarity of Criterion 2.12, and the establishment of a bright line between Medium and Low Impact Control Centers.

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

Yes

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Yes

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer

Yes

Document Name

Comment

Agree

Likes 0

Dislikes 0

Response

David Zwergel - Midcontinent ISO, Inc. - 2

Answer

Yes

Document Name

Comment

MISO appreciates the additional clarity of Criterion 2.12, and the establishment of a bright line between Medium and Low Impact Control Centers.

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

IESO supports the comments submitted by NPCC

No further comment on this question

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Yes

Document Name

Comment

EI member companies generally support this change.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer

Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 1.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer

Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

Yes

Document Name

Comment

Southern Company agrees with the proposed modification and appreciates the establishment of a bright line criteria between Low and Medium Impact Control Centers.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer

Yes

Document Name

Comment

"Please see comments submitted by the Edison Electric Institute"

Likes 0

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name** Dominion**Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Kevin Salsbury - Berkshire Hathaway - NV Energy - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nick Batty - Keys Energy Services - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Becky Webb - Exelon - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Eric Smith - NaturEner USA, LLC - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Andrea Barclay - Georgia System Operations Corporation - 4****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Neville Bowen - Ocala Utility Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Trey Melcher - Lower Colorado River Authority - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Thomas Savin - New York Power Authority - 6

Answer

Document Name

Comment

We agree that the proposed revision adds clarity to differentiate between medium- and low-impact BES Cyber Systems at Control Centers. However, simple changes to the proposal would avoid TO control room inclusion within the usage of the term "Control Center," which may create a lack of clarity under other NERC Reliability Standards that use the defined term "Control Centers." Our position is that the language proposed below ensures TO control room BCS are appropriately categorized without using this revision to CIP-002 to create a new threshold for identifying Control Centers that perform the reliability tasks of a TOP.

We also recommend that the SDT consider if conforming changes to CIP-002 Attachment 1 Criteria 1.3 are needed for consistency with its proposed changes to CIP-002-6 Criteria 2.12, or our proposed changes below.

As an alternative, we propose the following modification to Criteria 2.12 to address TO control rooms that have the capability to perform monitoring and control of BES Transmission Lines while keeping the weighting proposed by the SDT (proposed language in bold + underline):

*"Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines, **or facilities hosting operating personnel that have the capability to monitor and control BES Transmission Lines**, with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. **The "aggregate weighted value" for a facility hosting operating personnel that has the capability to monitor and control BES Transmission Lines is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line that could be monitored and controlled by the facility hosting operating personnel.**"*

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

Document Name

Comment

NCPA is not a Transmission Operator and has No Comment.

Likes 0

Dislikes 0

Response

2. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

Southern Company would like specific clarification within the Standard text in section 5, "Effective Dates". Southern asserts that the following text:

"By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.",

should be changed to

"By that time, the Responsible Entity must apply all **CIP** Reliability Standard requirements applicable to its new categorization to the new BES Cyber System."

to provide this additional clarity.

We would also like the SDT to consider modifications to the language "capable of impacting the BES". There are many aspects to commissioning assets that are complex and it is often such that it cannot be represented by a single date, but rather a series of steps across a period of time. The integration of new generation resources – especially Wind and to some extent Solar facilities – involves bringing blocks of generation on-line piecemeal, in many cases under local control with multiple vendors and contractors involved. During this transition period there are often temporary control measures in place and until the projects have been tested, integrated and transferred to the Control Center(s). It is the full intent to appropriately secure facilities under development in both physical and cyber aspects. Southern asserts that, at a *minimum*, the compliance effective date for new generation resources should be on the date it is declared "commercial" under its Interconnection Agreement.

Alternately, Southern proposes that if compliance must be met "upon commissioning," then we request that this only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with all applicable CIP requirements "upon commissioning, as identified by the Responsible Entity." This modification accommodates the complexity associated with the commissioning process and allows for the additional needed flexibility in commissioning different types of assets containing low impact BES Cyber Systems.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer No

Document Name

Comment

PG&E believes the text of “capable of impacting the BES” will lead to interpretation differences between Entities and ERO Audit Teams due to the subjective nature of the text. Could the impact occur when; a) the BCS is initially installed, b) when it is being tested, c) after testing, or d) when it is placed into production?

With new BCS installations occurring months before actual production usage, the subjective nature of “capable of impacting” could subject an Entity to an extended period of potential violations if their interpretation is different than the Audit Teams. PG&E, as an active observer to the CIP Standard Drafting Team (SDT) meetings covering this modification, understands the difficulty in trying to create an unambiguous way to indicate when new BCS need to be covered by the CIP Requirements. PG&E’s suggested correction for this condition is the creation of guidance, with examples of what would be considered “capable of impacting” for the different “asset” types in CIP-002. PG&E is willing to be part of the effort in drafting the guidance.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

No

Document Name

Comment

Unnecessarily Prescriptive:

We do not agree with the proposed modifications relating to “capable of impacting the BES.” This change from the v5 Implementation Plan is unnecessary and overly prescriptive. Specifically, the SDT has chosen to define “upon commissioning” without appreciating the complexity of commissioning or recognizing that commissioning is a process and not a point in time. The proposed change does not reflect the reality of cyber-physical systems. As defined in the NERC Glossary of Terms, the BES is comprised of Elements. These Elements include electrical devices such as “a generator, transformer, circuit breaker” etc. The BES Cyber Assets cannot be separated from the physical components that they control. As such, if a breaker is an Element and an Element is part of the BES, then there is no time at which the BES Cyber Asset is not “impacting the BES” since even though the circuit breaker switched out of service, it is still itself part of the BES. Ultimately, it appears that the changes proposed by the SDT in an attempt to provide clarity in certain circumstances, have inadvertently introduced unnecessary complexity and confusion into the commissioning process.

Alternative Proposal 1:

We propose that in place of the existing planned changes proposal that the SDT adopt the language as written in the version 5 Implementation Plan:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements” that contain periodic obligations as provided in the version 5 Implementation Plan.

Alternative Proposal 2:

If the SDT insists on requiring that compliance be met “upon commissioning,” then we request that this obligation only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with applicable periodic requirements within the first period following the commissioning as identified by the Responsible Entity, and with all other applicable requirements “upon

commissioning as identified by the Responsible Entity.” This modification recognizes the complexity of the commissioning process and allows for flexibility since the commissioning process is not the same for different types of assets or different types of entities.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer

No

Document Name

Comment

Clarifying planned and unplanned changes: they need to be more concise. The draft footnotes are too long and almost belong in the Glossary.

Likes 0

Dislikes 0

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer

No

Document Name

Comment

As the Regions seem to arbitrarily define Planned or Unplanned Changes, various situations could create serious compliance issues, especially for generation entities.

An example of this would be purchase of generation assets and controlling those assets from a Low Impact Control Center. Incorporating the control of those assets may possibly change the impact classification of that Control Center to Medium or even possibly High. As the generation sector of our industry is seeing increased sale and purchase of generation facilities (especially in the private equity arena), as well as a decrease in the amount of time for sales and purchases to close, this proposed change would place an undue and unobtainable burden to have such a Control Center compliant to the new impact classification immediately upon acquisition.

Until there are clearly defined definitions of Planned and Unplanned Changes which are administered uniformly and address such situations as described above, we do not support this proposal.

I suggest that the proposed definition of Unplanned Change in footnote 2 of Page 4 be modified to include this scenario as subpart (5):

(5) A change in the classification of a Control Center per application of CIP-002, R1 and/or R2 caused by the purchase of a generating facility that is incorporated for control in that Control Center following its acquisition.

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

No however I am willing to agree that all changes, regardless if Planned or Unplanned, should be treated equally. If Unplanned changes allow an entity two years to become compliant then NERC should not discriminate against those that have Planned changes. Both should be allowed two years to become compliant. Fairness!

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Propose including "and rely upon to perform reliability tasks."

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer

No

Document Name

Comment

The phrase "...effective upon the date the new BES Cyber System is capable of impacting the BES." is ambiguous and could lead to different interpretations of the "impact" date. An example would be when a new generator is being tested to validate it can sync to the grid before the BES Cyber System has been installed, tested, and placed in service. At this point in time, the generator can technically impact the BES, although in a non-substantive manner, but the generator owner will have coordinated with the RC/TOP/TP to make allowances for this testing and that the generator test run could end abruptly and accommodations are made to minimize any potential impacts. Dominion Energy suggests that the following language, used

by SERC and published on their website, be used in place of the phrase: "Newly built Elements that are classified as BES Elements under the BES definition should be compliant prior to that Element being placed in service and added to the pool of BES Assets."

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer

No

Document Name

Comment

As the Regions seem to arbitrarily define Planned or Unplanned Changes, various situations could create serious compliance issues, especially for generation entities.

An example of this would be purchase of generation assets and controlling those assets from a Low Impact Control Center. Incorporating the control of those assets may possibly change the impact classification of that Control Center to Medium or High. As the generation sector of our industry is seeing increased sale and purchase of generation facilities, as well as a decrease in the amount of time for sales and purchases to close, this would place an undue and unobtainable burden to have such a Control Center compliant to the new impact classification.

Until there are clearly defined definitions of Planned and Unplanned Changes which are administered uniformly and address such situations as described above, we do not support this proposal.

Likes 0

Dislikes 0

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer

No

Document Name

Comment

The revision is likely to be interpreted that the categorization of a BES Cyber System will become effective when the BES Cyber System is part of generation that is first tied to the grid. This does not allow the entity to perform necessary testing and commissioning online during a time period when the BA understands that the generation associated with the new BES Cyber System is not yet reliable. During the time when the BA understands this generation to be unreliable due to further testing, the BA's function maintains grid reliability without dependence on the load from the generation associated with the new BES Cyber System.

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

- Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, Implementation **Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.
- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.
- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. ...12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0

Dislikes 0

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer Yes

Document Name

Comment

“Please see comments submitted by the Edison Electric Institute”

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer

Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer

Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer

Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 2.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Yes

Document Name

Comment

EI member companies generally support this change.

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

No comment

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer

Yes

Document Name

Comment

Section A.5:

1. “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” This may be misleading in that the only “new” impact criterion in this version is 2.12. RF recommends the wording be changed to, “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets at least one criterion at a higher impact rating in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]”
2. The language is not clear that it applies to a new asset coming into scope as a BES asset, and therefore will have new low impact BES Cyber Systems (LIBCS). As the Standard does not require identification of LIBCS, but only identification of the assets containing LIBCS, it’s not clear that the language “planned change resulting in a new BES Cyber System” and “planned change resulting in a change in categorization for an existing BES Cyber System” will be effective in capturing new LIBCS. The language should directly address changes resulting in additional identified assets that contain LIBCS coming into scope for CIP-002. There are similar concerns for unplanned changes.
3. The language regarding initial performance of periodic obligations will result in very long lead times for some Requirements. For example, testing of an incident response plan for new low impact BES Cyber Systems (LIBCS) resulting from an unplanned change would not be required until 5 years after identification of the LIBCS. The initial performance of periodic requirements should be tightened to a more reasonable timeframe in order to reduce risk to the BES.

Section E is meant to incorporate the existing Interpretation. There are two problems with this:

1. The SDT did not fulfill the language of the NERC RoP regarding Interpretations: “The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.” [Standard Processes Manual, RoP Appendix 3A, Section 7] Since this revision of the Standard is an opportunity where the SDT can incorporate the Interpretation, it is incumbent upon the SDT to do so.
2. Placing the reference to the Interpretation in a section that is not identified by the Standard Processes Manual Section 2.5 may render the Interpretation unenforceable: “The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” [Standard Processes Manual, Section 2.5]

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Trey Melcher - Lower Colorado River Authority - 1

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Neville Bowen - Ocala Utility Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Eric Smith - NaturEner USA, LLC - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Becky Webb - Exelon - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Zwergel - Midcontinent ISO, Inc. - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nick Batty - Keys Energy Services - 4

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Tim Womack - Puget Sound Energy, Inc. - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Thomas Savin - New York Power Authority - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Bruce Reimer - Manitoba Hydro - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

3. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the responsible entity performs its review of identifications under Requirement R2, Part 2.1. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

NO, WE DO NOT ARGEE. Please see Consumers Energy response for question #2.

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer No

Document Name

Comment

As discussed in our answer to Question 2, arbitrary determinations of Planned and Unplanned Changes must be addressed across the regions.

Additionally, in some cases, where the region determines a planned change raises the impact from Low to Medium or High, the entity may be unable to meet all the requirements related to the new impact level, especially due to technical and resource limitations within the time period.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer No

Document Name

Comment

Reclamation recommends the categorization of the BES Cyber System become effective upon the date the modified BES Cyber System is capable of impacting the BES. This will allow time for testing and returning existing equipment to service without the need to document compliance of equipment that is not capable of causing an adverse reliability impact.

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer

No

Document Name

Comment

While AZPS generally agrees with and supports the concepts regarding Planned Changes, it is concerned that the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” in the definition of a Planned Change could be interpreted more broadly than was intended and, therefore, impose an undue burden on Registered Entities.

More specifically, where a change is occurring that may impact a Responsible Entity’s asset identification, but that is not being planned or performed by that Responsible Entity, the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” assumes that such advance knowledge occurs far enough in advance of commercial operations for the impacted Responsible Entity to identify the impacts and implement compliance measures. Such notification is not within the control of the impacted Responsible Entity and the implementing party may not fully realize or understand the impacts of its Planned Change on adjacent systems or facilities.

For these reasons, a Responsible Entity may not have knowledge of such impacts far enough in advance of commercial operations to timely identify the impacts and implement the required compliance measures. More specifically, if a Responsible Entity received notification from an adjacent system or a project participant that modifications were being made six months prior to the commercial operation of such modification, the Responsible Entity, through no fault of its own, would likely have a reportable non-compliance as it would have “advance knowledge” of the “Planned Change,” but would not have enough time to identify impacts and implement compliance measures. Thus, in certain circumstances, the revisions to the concept of a Planned Change create an unrealistic or infeasible expectation. The definition of “Unplanned Changes” may be intended to cover this scenario, but the ambiguity of the language defining a “Planned Change” could lead to confusion and/or overlap. To rectify this, AZPS recommends the following revisions to sentence 1 of footnote 1:

Planned changes are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or where the Responsible Entity received notification of such change from the implementing party at least 24 months prior to commercial operations.

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Propose including "and rely upon to perform reliability tasks."

Likes 0

Dislikes 0

Response**Marty Hostler - Northern California Power Agency - 5**

Answer

No

Document Name

Comment

No if the drafting team feels it is necessary to categorize more than every 15-months they should change that language in the standard. I don't recall NERC or the SAR requesting/authorizing this action.

Additionally, IRC 2.1 and 2.11 are Impact Rating Criteria based on historical data. At least every 15-months an entity is to look back at the last 12-months of data and determine the Facilities' impact rating. If these Planned and Unplanned Change definitions are to go into effect then IRC 2.1 and 2.11 need to be excluded or deleted from the standard.

Likes 0

Dislikes 0

Response**Gerry Adamski - Cogentrix Energy Power Management, LLC - 5**

Answer

No

Document Name

Comment

As discussed in our answer to Question 2, arbitrary determinations of Planned and Unplanned Changes must be addressed across the regions.

Additionally, in some cases, where the region determines a planned change raises the impact from Low to Medium or High, the entity may be unable to meet all the requirements related to the new impact level, especially due to technical and resource limitations within the time period.

I urge the drafting team to consider the addition of subpart 5 to the definition of Unplanned Change in footnote 2 on Page 4 of the standard:

(5) A change in the classification of a Control Center per application of CIP-002, R1 and/or R2 caused by the purchase of a generating facility that is incorporated for control in that Control Center following its acquisition.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer

No

Document Name

Comment

Modifying Attachment 1 – Medium 2.1.2: while it is better to establish an MW value, it should be done across all High, Medium and Low. If MW value is going to be the risk bar, then let them revise Attachment 1 and simplify it.

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

No

Document Name

Comment

Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

No

Document Name

Comment

Not consistent with CIP-002 R2.1:

We do not agree with the proposed modifications for Planned Changes resulting in a new BES Cyber System. BES Cyber Systems do not receive an impact rating except through performance of the process required in CIP-002 R1. CIP-002 itself recognizes that BES Cyber Systems only receive a rating upon the application of this process by specifically requiring that the identifications resulting from this

process be reviewed and updated at least once every 15 calendar months (CIP-002 R2.1). If the application of CIP-002 R1 is in fact a continuous obligation, then there is no basis for CIP-002 R2, Part 2.1 to exist.

No Rationale for Modifications to Planned Changes:

Further, the SDT has provided no rationale for the modifications related to planned and unplanned changes. No Rationale Document has been developed and the summary in this informal comment form barely mentions this change even though it has a rippling impact across the entire suite of CIP standards.

Contradiction to V5 Implementation Plan:

The SDT appears to have taken it upon themselves to change the basis by which the CIP requirements become effective that was established in the CIPv5 implementation plan and existed prior to that in the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities (IPFNICCAANRE). In the IPFNICCAANRE, planned changes were classified as a category 3 scenario and specified to be “Compliant upon Commissioning.” Under the basis of version 3 where there were a limited number of Critical Assets and the standards themselves were specifically asset based, this approach was feasible. Additionally, version 3 of CIP-002 contained an obligation to update the CIP-002 list of Critical Cyber Assets “as needed.” Notably this obligation was removed in version 5. The version 5 Implementation Plan specifically says that “Planned changes refer to any changes of the electric system or BES Cyber System as identified through the annual assessment under CIP-002-5, Requirement R2, which were planned and implemented by the responsible entity.” The v5 implementation plan goes on to say that if a “modernization activity” is performed where Cyber Assets are installed that meet the criteria in CIP-002-5 Attachment 1, then the new Cyber Assets must be in compliance “upon the commissioning of the modernized transmission substation.” Notably in this scenario in order for the changes to have been identified under CIP-002 during the annual assessment, the transmission facility must have existed and had existing Cyber Assets at the time of the annual assessment. This example is no different than the execution of a recovery plan at an existing transmission substation. One would not argue that since a BES Cyber System failed and needed to be replaced that the replacement BES Cyber System would not need to be in compliance until the next application of CIP-002. However, in the event that a facility or a BES Cyber System did not exist at the time of the annual CIP-002 assessment, then the cyber system has no assigned impact categorization and cannot be obligated to meet the suite of CIP requirements. Specifically, the v5 Implementation Plan goes on to state “For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the Version 5 CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System...” The SDT has provided no basis for changing this established expectation in its newly modified Effective Date “clarifying language.”

New Conflicting Language:

The SDT has introduced new conflicting language into the Effective Date section. The new language is conflicting as to when the initial performance of periodic requirements needs to be performed. Specifically, in section 5.1, the language states “By that time, the Responsible Entity must apply all Reliability Standard requirements applicable...” This specification of “all” does not indicate any exceptions. Three paragraphs later, the section states “For requirements that contain periodic obligations, initial performance of those new obligations...shall occur within the first period following the date the new BES Cyber System could adversely impact the BES.” These two statements conflict with each other. It is apparent that the SDT intended to provide additional time for periodic obligations. As such, it should not state that “all” requirements must be applied by the date if it intends to provide additional time for requirements with periodic obligations.

Alternative Proposal 1:

We propose that in place of the existing planned changes proposal that the SDT adopt the language as written in the version 5 Implementation Plan:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements” that contain periodic obligations as provided in the version 5 Implementation Plan.

Alternative Proposal 2:

If the SDT insists on requiring that compliance be met “upon commissioning,” then we request that this obligation only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with applicable periodic requirements within the first period following the commissioning as identified by the Responsible Entity, and with all other applicable requirements “upon commissioning as identified by the Responsible Entity.” This modification recognizes the complexity of the commissioning process and allows for flexibility since the commissioning process is not the same for different types of assets or different types of entities.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer

No

Document Name

Comment

PG&E believes the text of “meets the new impact criteria in Attachment 1” will lead to interpretation differences between Entities and ERO Audit Teams due to the subjective nature of the text. Could the “meets the new impact criteria” occur when; a) the change happens on initial installation, b) during testing, c) after testing, or d) when finally placed into production?

Changes to existing facilities occur months before actual production usage and the subjective nature of “meets the new impact criteria in Attachment 1” could subject an Entity to an extended period of potential violations if their interpretation is different than the Audit Teams. PG&E, as an active observer to the CIP Standard Drafting Team (SDT) meetings covering this modification, understands the difficulty in trying to create an unambiguous way to indicate when changes to BCS require changes in the application of the CIP Requirements. PG&E’s suggested correction for this condition is the creation of guidance, with examples on what would be considered “meets the new impact criteria in Attachment 1” for the different “asset” types in CIP-002. PG&E is willing to be part of the effort in drafting the guidance.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

No

Document Name

Comment

Southern does not agree with the proposed modifications for Planned Changes resulting in a new BES Cyber System. Until a BCS goes through the evaluation process required by CIP-002 R1, it does not have an impact rating. As such, if registered entities are to continually assess new assets, there is no real reason to have CIP-002 R2 part 2.1 as these required evaluations should have happened already, negating the need for a cycle.

Likes 0

Dislikes 0

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes	0
Dislikes	0

Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
<p>Section A.5:</p> <ol style="list-style-type: none"> 1. “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” This may be misleading in that the only “new” impact criterion in this version is 2.12. RF recommends the wording be changed to, “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets at least one criterion at a higher impact rating in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” 2. The language is not clear that it applies to a new asset coming into scope as a BES asset, and therefore will have new low impact BES Cyber Systems (LIBCS). As the Standard does not require identification of LIBCS, but only identification of the assets containing LIBCS, it’s not clear that the language “planned change resulting in a new BES Cyber System” and “planned change resulting in a change in categorization for an existing BES Cyber System” will be effective in capturing new LIBCS. The language should directly address changes resulting in additional identified assets that contain LIBCS coming into scope for CIP-002. There are similar concerns for unplanned changes. 3. The language regarding initial performance of periodic obligations will result in very long lead times for some Requirements. For example, testing of an incident response plan for new low impact BES Cyber Systems (LIBCS) resulting from an unplanned change would not be required until 5 years after identification of the LIBCS. The initial performance of periodic requirements should be tightened to a more reasonable timeframe in order to reduce risk to the BES. <p>Section E is meant to incorporate the existing Interpretation. There are two problems with this:</p> <ol style="list-style-type: none"> 1. The SDT did not fulfill the language of the NERC RoP regarding Interpretations: “The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of 	

the applicable Requirement.” [Standard Processes Manual, RoP Appendix 3A, Section 7] Since this revision of the Standard is an opportunity where the SDT can incorporate the Interpretation, it is incumbent upon the SDT to do so.

2. Placing the reference to the Interpretation in a section that is not identified by the Standard Processes Manual Section 2.5 may render the Interpretation unenforceable: “The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” [Standard Processes Manual, Section 2.5]

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

No comment

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

EI member companies generally support this change.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas

City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 3.

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer Yes

Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Bruce Reimer - Manitoba Hydro - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Thomas Savin - New York Power Authority - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Tim Womack - Puget Sound Energy, Inc. - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Zwergel - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Rachel Coyne - Texas Reliability Entity, Inc. - 10****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Becky Webb - Exelon - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Eric Smith - NaturEner USA, LLC - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Neville Bowen - Ocala Utility Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Trey Melcher - Lower Colorado River Authority - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

4. Effective Date Section: Do you agree with the proposed modification to the unplanned changes section that provides 24 months for implementation of the requirements? If yes, please provide comments on why the timeframe is appropriate to assist the SDT with additional justification. If no, please provide your rationale and an alternate proposal.

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer No

Document Name

Comment

Although 24 months may be a reasonable amount of time for some substation projects either planned or unplanned, others can take more than 24 months due to circumstances beyond control, such as:

- - Scheduling outages,
 - Substation resources already assigned to planned work that cannot be delayed,
 - Vendor issues.

An example is changing an asset that contains Low Impact BES Cyber Systems to an asset containing Medium Impact BES Cyber Systems with External Routable Connectivity (ERC) at an entity that previously did not have ERC at any substation. Designing, purchasing, installing, and testing both an Electronic Access Control and Monitoring System (EACMS) and Physical Access Control System (PACS) could easily take 24 months or more. Also, the number of requirement parts applicable to Medium Impact BES Cyber Systems with ERC is significantly more than that of those without ERC. The additional work involved with those additional requirements will equate to even more periodic work. Determining an approach to compliance, developing the new policies and procedures, and training could also take 24 months or more. The additional work may require hiring new staff.

CenterPoint Energy Houston Electric, LLC recommends adding language to the Effective Dates section that provides a method for which an entity can extend the time needed to complete an unplanned project when it is apparent that the project will take more than 24 months.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

Southern Company proposes the following modifications:

“For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective **30** calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all CIP Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until **30** calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following a **planned change** shall occur within the first period prescribed in the requirement, either 1) following the date the new BES Cyber System could adversely impact the BES, or 2) the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period prescribed in the requirement after **30** calendar months from the date of notification or detection of the unplanned change.”

Southern believes that “unplanned changes” should be handled equivalently as those in TPL-001-4 R2.7.3 where a situation outside the Planner’s control occurs and an unexpected Corrective Action Plan (CAP) is required. The TPL standard accepts some risk such as non-consequential load loss until a CAP is in place. In the case of unplanned changes impacting compliance with the CIP Standards, a CAP or other plan could be developed and used to either proceed with increasing a facility’s BES Cyber System(s) and associated BES Cyber Asset’s impact classification to Medium Impact and moving to more CIP required controls, or alternatively to implement transmission system modifications (similar to segregating generating plant unit controls) that reduce risk and exposure by maintaining those BES Cyber System impact classifications at the low level. Southern requests the SDT consider and propose language allowing an Entity the flexibility to identify transmission improvements or system changes to remove or reduce the risk and exposure to the BES that accompanies unplanned changes, as well as provide the requisite time to make those improvements or changes that would help retain the associated BES Cyber Systems at a low impact classification rather than an Entity being required to enter into a long term financial and compliance burden if they were to rise from Low Impact to Medium Impact.

For example, the financial and compliance burden with having to comply with CIP Standards requirements applicable to Medium Impact BES Cyber Systems is tremendous, and can be compounded for an Entity in the event of unplanned changes that increase the impact classification of BES Cyber Systems. In those instances where an Entity chooses to make Transmission system improvements or modifications to keep applicable BES Cyber System in a Low Impact classification, but those improvements or changes will take 32 months to complete, from a risk-based perspective, what benefit or reduction of risk is provided should an entity have to make such a financial and organizational investment to comply with the CIP requirements applicable to Medium Impact BES Cyber Systems for only 2 months?

Southern requests the SDT consider that if a CAP or other plan developed as a result of an unplanned change includes steps to increase BES Cyber System impact ratings from Low Impact (or out of scope) to Medium Impact, the implementation time should be 30 months. This is an infrequent activity, but this time is warranted with the tremendous amount of Transmission work already being planned, and the additional time required to clarify notification/detection, scope of work, obtain budget dollars, schedule design disciplines, procure material, and complete construction for a very rare occurrence.

If a CAP or other plan is developed as a result of an unplanned change and is intended to include a transmission system modification, then more than 30 months may be needed to plan for and make the subsequent Transmission system modifications depending on the scope of the project. Southern recommends the SDT consider a process be available to Registered Entities to have the flexibility to implement a CAP or other plan that is shared with the ERO and tracked to completion as a mitigating measure for reducing BES exposure and risk by keeping BES Cyber System impact classifications at the Low Impact level.

For changes to BES Cyber System impact classifications associated with Control Centers, the compliance obligations for a Control Center containing Low Impact BES Cyber Systems compared to one that now has Medium Impact BES Cyber Systems as a result of an unplanned change are

substantially different and greatly exceed the Low Impact requirements. For instance, should a Generation Owner decide to repower wind turbines and push a TOP's Control Center over 1500 MW, the TOP will have significant work to do upon notification from the GO of this unplanned change. For such an unplanned change, 30 months is warranted in order for the TOP to meet the financial and compliance burdens of having a BES Cyber System(s) with increased impact classifications.

In each of the examples above, Southern asserts that the requested 30 months will allow for a more thorough review of all potential solutions.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

No

Document Name

Comment

For the reasons outlined in questions 2 and 3, we also do not agree with the 24 months for implementation of unplanned changes. In particular, we believe that the SDT should adopt the language included in the Version 5 Implementation Plan that states "For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements...according to the following timelines, following the identification and categorization of the affected BES Cyber System." This language necessarily recognizes that all timeframes for CIP-002 start with the performance of the annual CIP-002 process.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

No

Document Name

Comment

While Texas RE appreciates timeframes around planned and unplanned changes, the language is vague and will cause confusion. The Implementation Plan and the Effective Date section should work together. Texas RE recommends using the verbiage from the Implementation Plan rather than the use of the new term "first period" from the Effective Date section. This appears to be the first time this term has been used in the context of effective dates and with no explanation, there could be confusion as to when and how long the first period is.

The Implementation Plan, on the other hand, states: Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a. Texas RE prefers this verbiage than the “first period” term as it is more clear and would be consistent with how Implementation Plans have been written in the past.

Additionally, Texas RE suggests defining planned and unplanned changes to reduce ambiguity and vagueness. Texas RE recommends that entities have 24 months from the identification of a change. As written, it is unclear how long in the future a change is known could be considered an unplanned change. For example, Footnote 2, example 1, points to Criterion 2.3 which states planning horizon of more than a year. If it is under a year, do entities have 24 months to come into compliance? If it is over a year, do entities get 24 months from that date to come into compliance? If unplanned asset is identified as coming after 24 months, it should be treated as planned. In example 4, entities should know far in advance whether there will be additional load. How far in advance is considered planned?

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer

No

Document Name

Comment

24 months would not allow for the time necessary to get required budget and implementation required. IID is recommending that 36 months would be a more adequate time to fund and implement necessary requirements.

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

No however I am willing to agree that all changes, regardless if Planned or Unplanned, should be treated equally. If Unplanned changes allow an entity two years to become compliant then NERC should not discriminate against those that have Planned changes. Both should be allowed two years to become compliant. Fairness!

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer No

Document Name

Comment

The proposed timeframe is not in line with prior practice. 12 months has been prior practice. RF is not aware of any entity having difficulty with this timeframe.

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer No

Document Name

Comment

The proposed implementation timeline for a large facility such as a generator moving from a Low to Medium Impact could take substantially more time than 24 calendar months. Recommend increasing the timeline to 36 calendar months. Suggest the SDT tie the implementation timeline to the size of the asset or number of Cyber Systems associated with the asset. This is probably not a "one size fits all".

Likes 0

Dislikes 0

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer Yes

Document Name

Comment

"Please see comments submitted by the Edison Electric Institute"

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Ameren agrees with the EEI in response to this question.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer Yes

Document Name

Comment

PG&E believes the 24 month time-frame is sufficient to apply the necessary Requirement changes when the impact rating goes from low to medium, or medium to high. While PG&E has not experienced changes in impact rating that would elevate a BCS impact rating, our experience on the application of the Requirements for medium and high BCS does not suggest a longer time-frame would be necessary.

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

OPG concurs with the RSC comment.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 4.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

EEl member companies support the SDT’s proposed 24-month implementation period for unplanned changes. Unplanned changes can have significant impacts on internal company processes and associated capital budgets, which can take as long as 12 months for approval before the funds can be allocated. We also note that unplanned changes, including recategorizing of control centers from Low Impact to Medium Impact, represent a major effort that places substantial demands on scarce technical resources. Moreover, a 24-month Implementation period is not without Industry precedent for compliance with substantial changes involving CIP Standards. In FERC Order 791 (Ref. 145 FERC 61,160; Docket No. RM13-5-000: Version 5 Critical Infrastructure Protection Standards; Issued November 22, 2013) the Industry was afforded a 24-month implementation period to ensure entity compliance was achieved for High and Medium Impact BES Cyber Systems. While we recognize that the transition to CIP Version 5 was a significant Industry effort, the efforts to transition a control center (worst case) from Low Impact to Medium Impact could represent similar challenges for entities that only have Low Impact BES Cyber Systems.

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric - 3

Answer Yes

Document Name

Comment

We support the comments provided by the FMPA:

We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn’t seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*” This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name

Comment

Comments: We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn't seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*" This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer Yes

Document Name

Comment

We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn't seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*" This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
ITC concurs with comments submitted by EEI:	
<p>"EEI member companies support the SDT's proposed 24-month implementation period for unplanned changes. Unplanned changes can have significant impacts on internal company processes and associated capital budgets, which can take as long as 12 months for approval before the funds can be allocated. We also note that unplanned changes, including recategorizing of control centers from Low Impact to Medium Impact, represent a major effort that places substantial demands on scarce technical resources. Moreover, a 24-month Implementation period is not without Industry precedent for compliance with substantial changes involving CIP Standards. In FERC Order 791 (Ref. 145 FERC 61,160; Docket No. RM13-5-000: Version 5 Critical Infrastructure Protection Standards; Issued November 22, 2013) the Industry was afforded a 24-month implementation period to ensure entity compliance was achieved for High and Medium Impact BES Cyber Systems. While we recognize that the transition to CIP Version 5 was a significant Industry effort, the efforts to transition a control center (worst case) from Low Impact to Medium Impact could represent similar challenges for entities that only have Low Impact BES Cyber Systems."</p>	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed	
Answer	Yes
Document Name	
Comment	
We agree with 24 months for the implementation of requirements for unplanned changes. Unplanned changes can have significant impacts and place substantial demands on technical resources, depending upon the scope of the unplanned changes.	

Likes 0

Dislikes 0

Response

David Zwergel - Midcontinent ISO, Inc. - 2

Answer Yes

Document Name

Comment

Example: The compliance obligations for a Medium Impact Control Center are substantial and greatly exceed the Low Impact requirements. One can easily envision a GO repowering wind turbines and pushing a TOP's Control Center over 1500 MW (Criteria 2.11 and 2.13). Assuming each is a different Responsible Entity, the TOP will have significant work to do upon notification from the GO of this unplanned change.

Likes 0

Dislikes 0

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer Yes

Document Name

Comment

The entity has no prior expectation for implementing either Medium or High Impact requirements prior to the notification from the Planning Coordinator or Transmission Planner or Reliability Coordinator, etc. or that a parent organization has purchased a generating facility that is now being placed under your control in an existing Control Center. In this regard, it is unrealistic for the entity to coordinate and implement an effective and robust CIP program in a rushed manner. Furthermore, cyber assets need to be specified, ordered, configured, and installed, training programs developed after a full suite of procedures are drafted, and above all, a secure network infrastructure created to protect the most important cyber assets. These activities presume funding is made available for an unbudgeted project in the current year. On the whole, a project of this type requires at least a year for a thoughtful specification, budgeting, and implementation. So the 24 months proposal is entirely adequate.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer Yes

Document Name

Comment

The 24-month timeframe is appropriate because it is commensurate with the initial implementation plan of CIP-002-5.1a. The 24-month timeframe allows sufficient time for entities to implement compliance measures for changes that the entity did not originally have scoped for compliance (e.g., budget cycles, procurement timeframes, and documentation).

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer

Yes

Document Name**Comment**

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer

Yes

Document Name**Comment**

Example: The compliance obligations for a Medium Impact Control Center are substantial and greatly exceed the Low Impact requirements. One can easily envision a GO repowering wind turbines and pushing a TOP's Control Center over 1500 MW (Criteria 2.11 and 2.13). Assuming each is a different Responsible Entity, the TOP will have significant work to do upon notification from the GO of this unplanned change.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
AEP supports the proposed modification to the unplanned changes section that provides 24 months for the implementation of the requirements. AEP feels this would provide sufficient time to accomplish all the physical changes necessary to move from compliance for an asset containing low impact BES Cyber Systems to one where all the BES Cyber Systems are instantly categorized as medium.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
24 months should provide a Responsible Entity with enough time to implement all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber Systems due to unplanned changes.	
Likes 0	
Dislikes 0	
Response	
Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC	
Answer	Yes
Document Name	

Comment

Yes. 24 months should be adequate in most cases.

Likes 0

Dislikes 0

Response**LaTroy Brumfield - American Transmission Company, LLC - 1**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Trey Melcher - Lower Colorado River Authority - 1**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Teresa Cantwell - Lower Colorado River Authority - 5**

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Neville Bowen - Ocala Utility Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Eric Smith - NaturEner USA, LLC - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Becky Webb - Exelon - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nick Batty - Keys Energy Services - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Kevin Salsbury - Berkshire Hathaway - NV Energy - 5****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

5. Implementation Plan: The SDT modified the Implementation Plan. Do you agree with the proposed Implementation Plan?

a. If yes, please provide comments on why the timeframes are appropriate to assist the SDT with additional justification.

b. If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer No

Document Name

Comment

To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is **twenty-four (24) calendar months** after the effective date of the applicable governmental authority's order approving the standard.

Likes 0

Dislikes 0

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer No

Document Name

Comment

Either the implementation timeline needs to be increased or the Implementation Plan for the effective date of the standard needs to be increased.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer No

Document Name

Comment

Reclamation recommends the following changes to the proposed implementation plan:

Initial Performance of Periodic Requirements - Reclamation recommends CIP-002-6 become effective no earlier than 24 months after the applicable governmental entity's order approving the standard to allow entities flexibility to determine the appropriate implementation.

Reclamation agrees with the Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12. A longer implementation period may be needed if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System.

Reclamation agrees that any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.

Reclamation agrees that Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

No. I am willing to agree to have Transmission Owners that have been inadvertently categorized as medium impact allowed to immediately be recategorized to low impact. Two-years should be the standard implementation time frame for the rest of the industry if their rating is to increase. Also I thought the STB was suppose to redefine Control Centers, we had alot of discussion but I don't recall seeing any results.

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer

No

Document Name

Comment

IID is proposing a 12 month effective date after approval due to budget needs if an impact rating on facility were to change.

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

No

Document Name

Comment

Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

No

Document Name

Comment

Texas RE has two main concerns with the Implementation Plan as written: planned and unplanned changes, and the retirement of CIP-002-5.1a. Regarding the first matter, the Implementation Plan has this statement: **“Planned or Unplanned Changes** Any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.” Since planned and unplanned changes are mentioned in other Reliability Standards, Texas RE is concerned of the implications of this statement. For example, CIP-013-1 has planned and unplanned changes referenced with exact timelines: “For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-005-6, CIP-010-3, and CIP-013-1 on the update of the identification and categorization of the affected BES Cyber System.

For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-005-6, CIP-010-3, and CIP-013-1 according to a specific timeline, following the identification and categorization of the affected BES Cyber System. The unplanned timelines for FERC approved CIP-013-1 are different from those proposed in CIP-002-6. The Implementation Plan for CIP-002-6 should not affect the Implementation Plan for CIP-013-1, since CIP-013-1 is approved by FERC.

Alternatively, the SDT could embark on a project to define planned and unplanned changes in the NERC Glossary as suggested in Texas RE’s comment to #4. This would include an analysis to determine which standards currently use those terms and how those terms are used. Having a clear definition would reduce the ambiguity and vagueness of those terms.

Second, the Implementation Plan contains the following statement regarding the phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12: “If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.” Since CIP-002-5.1a is being proposed to be retired immediately prior to the effective date of CIP-002-6, Texas RE is concerned there may be a gap in that 24 month time period.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

No

Document Name

Comment

We do not believe that the revisions in CIP-002 can be implemented “immediately” following FERC approval. In order to demonstrate compliance with CIP-002, responsible entities have been expected to provide evidence of the consideration and application of each and every criterion in Attachment 1 even when they do not change the impact categorization of any BES Cyber Systems. The modifications to criterion 2.12 are substantial. Even in the case where the newly modified criteria does not change the categorization of any BES Cyber Systems, time is needed in order to assess the new criterion and apply it against our systems. Additionally, time is needed to update process documentation. The Implementation Plan provides a 24 month implementation interval where the modified criterion increases the impact rating of a BES Cyber System. We recommend that the same length of time be provided to all responsible entities.

Likes 0

Dislikes 0

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer

No

Document Name

Comment

Entities should identify the facility according to CIP-002-6 criteria, and not go back to CIP-002-5.1a. Their documentation needs to provide if a higher categorization was determined, along with the date, and if it is planned or unplanned. Otherwise, there is more room for confusion and compliance risks.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

No

Document Name

Comment

Southern Company asserts that the 30-month timeframe is needed for a significant change such as a Control Center containing Low Impact BES Cyber Systems being reclassified as having Medium Impact BES Cyber Systems. Southern requests the SDT propose a 30-month implementation period, rather than 24 months, to align with the following proposed edits:

“...medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6...”

to

“...medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until **30** months after the effective date of CIP-002-6...”.

For entities who only currently have Low Impact Control Centers, maintaining compliance throughout the transition and beyond would require a substantial increase in budget allocation, manpower and planning, all of which take time.

Likes 0

Dislikes 0

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer

No

Document Name

Comment

Please see response to Question 4.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Medium Impact compliance obligations greatly exceed those for Low Impact, with Control Centers being the most extreme case. The time allotted for meeting these obligations needs to be sufficient, especially for any Responsible Entities not previously required to comply with CIP-004 through CIP-011.

The proposed 24 months is consistent with the implementation plan passed for CIP-003 through CIP-009 version 2 and 3 standards for Responsible Entities in Category 1 that had not previously identified Critical Cyber Assets and thus had no previous exposure to these standards.

Given the addition since then of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.

Likes 0

Dislikes 0

Response

Bruce Reimer - Manitoba Hydro - 1

Answer Yes

Document Name

Comment

We think completing compliance tasks within 24 months is a reasonable timeframe for the revisions to Criterion 2.12 resulting in a higher impact level categorization of a BES Cyber System (from low impact to medium impact).

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer Yes

Document Name

Comment

The proposed timeframe aligns with the 15 calendr month cycle in CIP-002-5.1a R2.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

The proposed timeframes are consistent with good business practice and with good security practice.

Likes 0

Dislikes 0

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer Yes

Document Name

Comment

Please see response to Q4.

Likes 0

Dislikes 0

Response	
David Zwergel - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
<p>Medium Impact compliance obligations greatly exceed those for Low Impact, with Control Centers being the most extreme case. The time allotted for meeting these obligations needs to be sufficient, especially for any Responsible Entities not previously required to comply with CIP-004 through CIP-011.</p> <p>The proposed 24 months is consistent with the implementation plan passed for CIP-003 through CIP-009 version 2 and 3 standards for Responsible Entities in Category 1 that had not previously identified Critical Cyber Assets and thus had no previous exposure to these standards.</p> <p>Given the addition since then of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.</p>	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed	
Answer	Yes
Document Name	
Comment	
<p>We like the Implementation Plan as is.</p> <p>We agree with 24 months for the implementation of requirements for unplanned changes. Unplanned changes can have significant impacts and place substantial demands on technical resources, depending upon the scope of the unplanned changes.</p>	
Likes	0
Dislikes	0
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	

Comment

ITC concurs with comments submitted by EEI:

"EEI member companies support the timeframes provided within the SDT's Implementation Plan and believe that the time allocated is necessary due to substantial company efforts necessary for transitioning from a Low Impact to Medium Impact. A more detailed explanation of why we feel a 24-month implementation period for unplanned changes is necessary is provided in our response to question 4 (above)."

Likes 0

Dislikes 0

Response**Leonard Kula - Independent Electricity System Operator - 2**

Answer

Yes

Document Name

Comment

IESO agrees with the proposed Implementation Plan (a)

Likes 0

Dislikes 0

Response**Larry Heckert - Alliant Energy Corporation Services, Inc. - 4**

Answer

Yes

Document Name

Comment

Given the addition of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.

Likes 0

Dislikes 0

Response**sean erickson - Western Area Power Administration - 1**

Answer

Yes

Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI member companies support the timeframes provided within the SDT's Implementation Plan and believe that the time allocated is necessary due to substantial company efforts necessary for transitioning from a Low Impact to Medium Impact. A more detailed explanation of why we feel a 24-month implementation period for unplanned changes is necessary is provided in our response to question 4 (above).	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 5.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	Yes
Document Name	
Comment	
It is an appropriate timeframe to implement.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG concurs with the RSC comment.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
<p>1) The immediate nature of the effective date will allow those Entities with medium impact Transmission Control Centers that in reality should have been designated as low impact, immediate relief, with the ability to appropriately adjust their programs.</p> <p>2) The phased in implementation of 24 months for conditions resulting in a higher impact rating (low to medium) is sufficient based on PG&E experiences.</p> <p>3) The inclusion of the “planned” and “unplanned” conditions within CIP-002-6 is a welcomed improvement over the separate document used with the original CIP Version 5 Standards.</p>	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Ameren agrees with the EEI in response to this question.

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer	Yes
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Thomas Savin - New York Power Authority - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Chinedu Ochonogor - APS - Arizona Public Service Co. - 6****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Nick Batty - Keys Energy Services - 4****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMMPA

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Boody - Lakeland Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Becky Webb - Exelon - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Neville Bowen - Ocala Utility Services - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Trey Melcher - Lower Colorado River Authority - 1

Answer Yes

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

6. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

The proposed modifications to CIP-002 will substantially increase the cost of compliance and represent an undue burden to registered entities as proposed. They stand to change what is currently a periodic requirement to a real-time requirement.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer No

Document Name

Comment

No, the proposed modifications substantially increase the cost of compliance over prior versions of the standard as they introduce unjustified and undirected modifications that substantially increase the burden of compliance from an annual obligation to an ongoing real-time obligation. We propose instead that the SDT adopt the language in the existing approved Version 5 Implementation Plan.

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration - 1

Answer No

Document Name

Comment

Minor changes such as these tend to reverberate and translate into more work for entity's to ingest, coordinate and respond

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

No however I am will to agree that all changes regardless if Planned or Unplanned should be treated equally. I don't believe any of the new Planned and Unplanned Changes language is necessary. Additionally, I don't believe the proposal is cost effective or necessary. An agreement with Transmission Operators should have been negotiated.

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer

No

Document Name

Comment

As expressed in AZPS's response to Question 3 above, AZPS is concerned that the inclusion of the phrase "or with the Responsible Entity's advance knowledge" in the definition of a Planned Change could be interpreted more broadly than was intended and, therefore, impose an undue burden on Registered Entities. More specifically, where a change is occurring that may impact a Responsible Entity's asset identification, but that is not being planned or performed by that Responsible Entity, the inclusion of the phrase "or with the Responsible Entity's advance knowledge" assumes that such advance knowledge occurs far enough in advance of commercial operations for the impacted Responsible Entity to identify the impacts and implement compliance measures. Such notification is not within the control of the impacted Responsible Entity and the implementing party may not fully realize or understand the impacts of its Planned Change on adjacent systems or facilities. For these reasons, a Responsible Entity may not have knowledge of such impacts far enough in advance of commercial operations to implement the required compliance measures in a cost effective manner.

If AZPS's recommended revisions for Question 3 above are incorporated into the standard, AZPS would agree that the proposed modifications provide entities with flexibility to meet the reliability objectives in a cost effective manner.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer

No

Document Name	
Comment	
Reclamation recommends the simplified Impact Rating Criteria described in the response to Question 1 will provide a more cost-effective manner of categorizing BES Cyber Systems and their associated BES Cyber Assets by reducing the cost of implementing the standard and the overall impact of CIP-002-6 and allowing entities to reduce the time spent “review[ing] the identifications in Requirement R1 and its parts (and update[ing] them if there are changes identified) at least once every 15 calendar months.”	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The language currently being proposed and commented upon in Q2 above is implemented, it could result in inefficient and expensive changes to the generator commissioning process.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
See comment on item 2.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No

Document Name	
Comment	
NO, WE DO NOT ARGEE. Please see Consumers Energy response for question #2.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer

Yes

Document Name

Comment

PG&E believes the modifications do provide sufficient flexibility in meeting the reliability objectives, but as noted in Questions 2 and 3, the subjective nature of “impact to the BES” and “meets the new impact criteria” needs to be addressed before final approval of the modifications.

In addition to the comments provided in Questions 2 and 3, the use of “adversely impact the BES” and “the date the existing BES Cyber System meets the new impact criteria in Attachment 1” in the last paragraph of Section 5.1 on PDF page 2 have the same condition PG&E has noted for Questions 2 and 3. The subjective nature of that text, will lead to differences in interpretations exposing an Entity to potential non-compliance. As suggested in Questions 2 and 3, PG&E believes the creation of guidance, with examples on what would be considered “capable of impacting” which is the same as “adversely impact the BES” and “date the existing BES Cyber System meets the new impact criteria” for the different “asset” types in CIP-002 would help alleviate this condition. PG&E also reiterates the statements in Questions 2 and 3 that they are willing to help in the drafting of that guidance.

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer

Yes

Document Name

Comment

We thank the SDT for allowing us to provide comments on these standards.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1,

3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 6.

Likes	0
-------	---

Dislikes	0
----------	---

Response

--

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5
--

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

Yes if the definition of Unplanned Changes incorporates the suggested change for including a newly purchased generating facility being added to a Low Impact Control Center, which results in an elevated classification. See reply to Q2 and Q3.

Likes	0
-------	---

Dislikes	0
----------	---

Response

--

Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

PPI agrees with WECC's comment to include a provision to allow for early TO adoption to reclassify TOCCs as low-impact under the revised Impact Rating Criteria 2.12.

Likes	0
-------	---

Dislikes	0
----------	---

Response

--

Steven Rueckert - Western Electricity Coordinating Council - 10**Answer** Yes**Document Name****Comment**

Although WECC agrees with the proposed modifications to CIP-002-6, some TO entities may wish to move sooner to reclassify their TOCCs as low impact BES Assets under the revised Impact Rating Criterion 2.12. A provision should be made to allow for such early adopters, as WECC recognizes the minimal risk to the reliability and security of the BES by such a reclassification to a lower risk BCS category.

Likes 1 Prairie Power, Inc., 1,3, Mercier Ginger

Dislikes 0

Response**LaTroy Brumfield - American Transmission Company, LLC - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Trey Melcher - Lower Colorado River Authority - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Teresa Cantwell - Lower Colorado River Authority - 5****Answer** Yes**Document Name**

Comment

Likes 0

Dislikes 0

Response**Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Neville Bowen - Ocala Utility Services - 3****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Eric Smith - NaturEner USA, LLC - 5****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Becky Webb - Exelon - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Zwergel - Midcontinent ISO, Inc. - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response**Nick Batty - Keys Energy Services - 4****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Anthony Jablonski - ReliabilityFirst - 10****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bruce Reimer - Manitoba Hydro - 1**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Lana Smith - San Miguel Electric Cooperative, Inc. - 5****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Neil Swearingen - Salt River Project - 1,3,5,6 - WECC****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer

Document Name

Comment

Minnesota Power will abstain from voting on this issue.

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

Ameren will remain silent on this matter.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE does not have comments on this question.

Likes 0

Dislikes 0

Response

Consideration of Comments

Project Name:	2016-02 Modifications to CIP Standards CIP-002-6 (Draft 3)
Comment Period Start Date:	6/3/2019
Comment Period End Date:	7/17/2019
Associated Ballots:	2016-02 Modifications to CIP Standards CIP-002-6 AB 3 ST

There were 69 sets of responses, including comments from approximately 148 different people from approximately 107 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Vice President of Engineering and Standards [Howard Gugel](#) (via email) or at (404) 446-9693

Questions

1. Attachment 1, Criterion 2.12: No changes have been added from the April 2018 ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.
2. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.
3. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the responsible entity performs its review of identifications under Requirement R2, Part 2.1. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.
4. Effective Date Section: Do you agree with the proposed modification to the unplanned changes section that provides 24 months for implementation of the requirements? If yes, please provide comments on why the timeframe is appropriate to assist the SDT with additional justification. If no, please provide your rationale and an alternate proposal.
5. Implementation Plan: The SDT modified the Implementation Plan. Do you agree with the proposed Implementation Plan?
 - a. If yes, please provide comments on why the timeframes are appropriate to assist the SDT with additional justification.
 - b. If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.
6. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	Tennessee Valley Authority	Kurtz, Bryan G.	Tennessee Valley Authority	1	SERC
					Grant, Ian S.	Tennessee Valley Authority	3	SERC
					Thomas, M. Lee	Tennessee Valley Authority	5	SERC
					Parsons, Marjorie S.	Tennessee Valley Authority	6	SERC
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Public Utility District No. 1 of Chelan County	Davis Jelusich	6		Public Utility District No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF, SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Jennifer Bray	Arizona Electric Power Cooperative	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Patrick Woods	East Kentucky Power Cooperative	1,3	SERC
					Shari Heino	Brazos Electric Power	5	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					Carl Behnke	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	SERC
FirstEnergy - FirstEnergy Corporation	Julie Severino	1		FirstEnergy	Aubrey Short	FirstEnergy - FirstEnergy Corporation	4	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Duke Energy	Katherine Street	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
					Lee Schuster	Duke Energy	3	SERC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrienne Collins	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion annd Con Ed	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
David Kiguel	Independent	NA - Not Applicable	NPCC					

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					John Hastings	National Grid	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable

1. Attachment 1, Criterion 2.12: No changes have been added from the April 2018 ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Anthony Jablonski - ReliabilityFirst – 10

Answer No

Document Name

Comment

The proposed language will not reduce the confusion regarding the identification of medium impact BES Cyber Systems. Many entities in the RF footprint have Control Centers that monitor BES Transmission Lines but only control those lines under direction from the registered TOP. The language in this Draft of CIP-002-6 does not make clear that these entities must identify BES Cyber Systems in such Control Centers as medium impact. RF suggests changing the phrase “that monitor and control” to “that are capable of controlling or monitoring.”

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The SDT proposes adding "to perform the reliability tasks of the Transmission Operator in real time" to better align the criteria with the Control Center definition. The SDT proposes the following text for Criterion 2.12., “Each Control Center or backup Control Center, not included in the High Impact Rating (H), used to perform the reliability tasks of the Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.” The phrase “monitor and control" includes both the directing the control of Transmission lines as well as the ability to operate the transmission line. The weighted value component of criteria 2.12 distinguishes those Control Centers’ BES Cyber Systems that should be medium versus low.

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer No

Document Name

Comment

Reclamation recommends simplifying the Impact Rating Criteria using the following methodology:

BES Cyber Systems are to be rated as high, medium, or low impact as follows:

A high impact BES Cyber System is a Control Center that has one or more of the following characteristics:

1. Is used to operate transmission lines of 500kV or above;
2. Supports a sum greater than 2500kV of transmission lines above 230kV;
3. Supports generation with an aggregate capacity greater than 3000MW;
4. Is identified as supporting an IROL or is necessary to avoid an Adverse Reliability Impact.

A medium impact BES Cyber System has one or more of the following characteristics:

1. Supports generation with the aggregate capacity between 1500 – 3000MW;
2. Supports a sum between 1500 – 2500kV of transmission lines above 230kV;
3. Supports a RAS that could negatively affect an IROL or that can perform automatic Load shedding of 300MW or more.

A low impact BES Cyber System has one or more of the following characteristics:

1. Supports a sum less than 1500kV of transmission lines above 230kV;
2. Supports transmission only between 100 – 230kV;
3. Supports generation with an aggregate capacity between 75 – 1500MW;
4. Supports any single generator greater than 20MW not already identified as a Medium Impact BES Cyber System;
5. Supports any Facilities that are designated a blackstart resource;

6. Supports any other RAS not already identified as a medium impact BES Cyber System.	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Modifying the impact ratings is outside the scope of this drafting team’s SAR.	
Spencer Tacke - Modesto Irrigation District – 4	
Answer	No
Document Name	
Comment	
Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Previously BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as medium impact. There was no threshold below which these systems could fall to be categorized as low impact. This criterion was added so that TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below a threshold and be considered low impact. That threshold was set at a level so that control of a small number of low impact assets that aggregate to less than two medium substations or below are categorized as low impact (note that control of a medium substation still makes the Control Center BES Cyber System high impact). Since a substation that met a 3,000 threshold is categorized as medium impact, and the Control Center must control two or more substations, the threshold was set at 6,000. If a Control Center’s span of control is less than that of two medium substations, its BES Cyber systems are categorized as low impact. In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, regardless of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The report	

used an average MVA line loading based on kV rating: 230 kV ->700 MVA, 345 kV -> 1300 MVA, 500 kV -> 2,000 MVA, and 765 kV -> 3,000 MVA.

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer No

Document Name

Comment

Texas RE appreciates the standard drafting team’s (SDT) work on revising this standard. Texas RE does have two concerns regarding Criterion 2.12. Primarily, Texas RE is concerned that the new Criterion 2.12 will result in some entities who were previously classified as medium impact to be classified as low impact, thus taking away the applicability of requirements CIP-003-CIP-011. Currently, under high impact rating 1.3, a Transmission Owner or Transmission Operator that owns Control Center(s) or backup Control Center(s) that is **not** used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 would **not** have identified high impact BES Cyber Systems. Under medium impact rating 2.12, however, those BES Cyber Systems would be identified as medium impact, which states, “2.12. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above”.

The Texas RE region has several entities in its footprint that could potentially change from a medium impact to low impact, which could reduce reliability as they would not be obligated to comply with CIP-003-CIP-011. The following scenarios could take place as a result of the change.

Texas RE appreciates the standard drafting team’s (SDT) work on revising this standard. Texas RE does have two concerns regarding Criterion 2.12. Primarily, Texas RE is concerned that the new Criterion 2.12 will result in some entities who were previously classified as medium impact to be classified as low impact, thus taking away the applicability of requirements CIP-003-CIP-011. Currently, under high impact rating 1.3, a Transmission Owner or Transmission Operator that owns Control Center(s) or backup Control Center(s) that is **not** used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10 would **not** have identified high impact BES Cyber Systems. Under medium impact rating 2.12, however, those BES Cyber Systems would be identified as medium impact, which states, “2.12. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above”.

The Texas RE region has several entities in its footprint that could potentially change from a medium impact to low impact, which could reduce reliability as they would not be obligated to comply with CIP-003-CIP-011. The following scenarios could take place as a result of the change.

- Example #1: A **TO or TOP** that monitors and controls substation(s) that are operating **less than 200 kV** and not connected to three or more other Transmission stations or substations and **does not** have an "aggregate weighted value" exceeding 3000 (Criterion 2.5) would not have identified high impact BES Cyber Systems. However, the current language of Criterion 2.12 would identify those BES Cyber Systems as medium impact.
- Example #2: A **TO or TOP** that monitors and controls substation(s) that are operating **345 kV** and are connected to **one or two** other Transmission stations or substations and **does not** have an "aggregate weighted value" exceeding 3000 (Criterion 2.5) would not have identified high impact BES Cyber Systems. However, the current language of Criterion 2.12 would identify those BES Cyber Systems as medium impact.

With the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12 uses the "aggregate weighted value" exceeding 6000. In both scenarios above, the identified medium impact BES Cyber Systems *could* now be identified as low impact BES Cyber Systems if all the BES Transmission Lines did not have an "**aggregate weighted value**" exceeding **6000**.

Secondly, Texas RE recommends adding a requirement that entities should consider the impact of locations where the impact of the sub-100 kV Transmission Line resulted in the inclusion of that line as a BES Transmission Line, since a sub-100kV system contributed to the September 2011 southwest blackout. In the aggregate weight table there is no provision for Transmission Lines below 100 kV that have been flagged as part of the weighting system.

Texas RE also noticed two additional items with regards to the standard. First, the rationale box for Criterion 2.12 states "The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV." This comment form, however, states "The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV." Texas RE inquires as to which is correct.

Lastly, Texas RE has the following additional comments regarding the Guidelines and Technical Basis:

- Texas RE is of the understanding that Guidelines and Technical Basis are being converted to Technical Rationale and/or Implementation Guidance in accordance with the Technical Rationale Transition Plan. Since CIP-002-6 is open for development, it

seems that the SDT should be following Track 2 of the Transition Plan. It also appears that the content related to Criterion 2.12 should be considered for development as Implementation Guidance and should follow the Compliance Guidance Policy.

- Under “Generation” on page 29, “Bas” should be “BAs”.
- On page 30, the second paragraph includes a reference to TPL-003, for which there is no currently effective version: “If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.” Texas RE recommends updating language to: “If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to an event identified in the TPL Standards, then BES Cyber Systems for that unit are categorized as medium impact.”
- On page 30, in the third paragraph, it states “The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.” This language is not used in TPL-001-4, but similar language addressing the use of non-consequential load loss is used in Footnote 12. Recommend updating this language to be consistent with the effective standards.
- On page 31, in the second bullet, “interconnection” should be capitalized as it is a defined term in the NERC Glossary.
- On page 31, under Transmission, the following statement appears to be out of date given the implementation of MOD-025-2: “Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities.” Texas RE recommends the SDT update that statement.
- On page 32 strike “Attachment 1 of” in the sentence starting with “Additionally...”. The link provided links to Attachment 1.
- On page 33, the second bullet from the bottom - The phrase “... and its Transmission provider” should be changed to “... and its Transmission Entity(ies)” as defined in NUC-001-3. In the last sentence on page 33, “Generation” should be lower case or changed from “Generation owner” to “Generator Owner”.
- On page 34, in the first full sentence, “for” should not be deleted after “BES Cyber Systems”.

- On page 34, in the third paragraph, there should be a space in “1500MW”.
- On page 34, the fourth paragraph references Load acting as a Resource (“LaaR”). Since LaaR does not exist anymore in the ERCOT region, Texas RE recommends updating this paragraph.
- On page 35, Texas RE requests the analysis and results of the analysis used by the SDT to validate that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk. There are 108 registered BAs, 19 RCs, and 181 TOPs that have Control Centers. GOPs and TOs acting as a TOP do not have clear numbers.
- Beginning on page 36, the Restoration Facilities section appears to have been written in 2012. Texas RE suggests the SDT review it and make necessary updates. For example, EOP-005-2 is no longer effective.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Previously BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as medium impact. There was no threshold below which these systems could fall to be categorized as low impact. This criterion was revised so TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below the medium impact threshold and be considered low impact. That threshold was set at a level so that control of a small number of low impact assets that aggregate to less than two medium substations are identified as low impact (note that control of a medium substation still makes the Control Center BES Cyber System high impact). Since a substation that met a 3,000 threshold is categorized as medium impact, and the Control Center must control two or more substations, the threshold was set at 6,000. -If a Control Center’s span of control is less than that of two medium substations, its BES Cyber systems are categorized as low impact due to the lower risk posed by the BES Cyber Systems. In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregate weighted value is used to account for the true impact to the BES, regardless of line kV rating and mix of multiple kV rated lines. The values were established based on the average MVA line loading detailed in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” After reviewing stakeholder comments, the SDT decided to revise Criterion 2.12 to remove ambiguity introduced by the monitor and control qualifiers. The SDT proposes removing “monitor and control” from the criterion and proposes inserting “used to perform the reliability tasks of the Transmission Operator”. The SDT proposes the following text for Criterion 2.12., “Each Control Center or backup Control Center, not included in the High Impact Rating (H), used to perform the reliability tasks of the Transmission Operator in real-time for BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and

controlled by the Control Center or backup Control Center.” -The SDT contends that the proposed revision clearly identifies medium impact BES Cyber Systems associated with Control Centers that perform the reliability tasks of the TOP.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer Yes

Document Name

Comment

Black Hills agrees with the approach, but wonder if there might be inconsistency among entities in how BES Transmission Lines are counted, i.e. does segmentation of a transmission path increase the "number" of lines?

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The SDT used the terms Bulk Electric System and Transmission Line, as defined in the Glossary of Terms Used in NERC Reliability Standards and has provided a supplemental technical basis that includes bullet points to consider when evaluating Transmission Lines in the application of Criterion 2.12.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
NSRF appreciates the additional clarity of Criterion 2.12, and the establishment of a bright line between Medium and Low Impact Control Centers.	
Likes	0
Dislikes	0
Response: The SDT thanks you for our comments.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes	0
Dislikes	0
Response: Please see the response to MRO NSRF's comments.	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Agree	
Likes 0	
Dislikes 0	
Response	
David Zwergel - Midcontinent ISO, Inc. – 2	
Answer	Yes
Document Name	
Comment	

MISO appreciates the additional clarity of Criterion 2.12, and the establishment of a bright line between Medium and Low Impact Control Centers.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator – 2

Answer Yes

Document Name

Comment

IESO supports the comments submitted by NPCC

No further comment on this question

Likes 0

Dislikes 0

Response: Please see the SDT's response to NPCC.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Yes

Document Name

Comment

EI member companies generally support this change.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer

Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 1.

Likes 0

Dislikes 0

Response: Please see the response to Edison Electric Institute's comments.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Jamie Monette - Allete - Minnesota Power, Inc. – 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response: Please see the response to Edison Electric Institute’s comments.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Southern Company agrees with the proposed modification and appreciates the establishment of a bright line criteria between Low and Medium Impact Control Centers.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments.

Kenya Streeter - Edison International - Southern California Edison Company – 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments.

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer	Yes
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response: Please see the response to Edison Electric Institute's comments.	
Stacy Lee - City of College Station – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginger Mercier - Prairie Power, Inc. - 1,3 – SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF	
Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Leanna Lamatrice - AEP – 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara – 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Bruce Reimer - Manitoba Hydro – 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. – 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes	0
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. – 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. – 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Nick Batty - Keys Energy Services – 4

Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed

Answer	Yes
Document Name	
Comment	
Likes	0

Dislikes	0
Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA</p>	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. – 4	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

Larry Watt - Lakeland Electric – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patricia Boody - Lakeland Electric – 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

sean erickson - Western Area Power Administration – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes	0
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Becky Webb - Exelon – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Eric Smith - NaturEner USA, LLC – 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neville Bowen - Ocala Utility Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Trey Melcher - Lower Colorado River Authority – 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniela Hammons - CenterPoint Energy Houston Electric, LLC – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Thomas Savin - New York Power Authority – 6

Answer

Document Name

Comment

We agree that the proposed revision adds clarity to differentiate between medium- and low-impact BES Cyber Systems at Control Centers. However, simple changes to the proposal would avoid TO control room inclusion within the usage of the term “Control Center,” which may create a lack of clarity under other NERC Reliability Standards that use the defined term “Control Centers.” Our position is that the language proposed below ensures TO control room BCS are appropriately categorized without using this revision to CIP-002 to create a new threshold for identifying Control Centers that perform the reliability tasks of a TOP.

We also recommend that the SDT consider if conforming changes to CIP-002 Attachment 1 Criteria 1.3 are needed for consistency with its proposed changes to CIP-002-6 Criteria 2.12, or our proposed changes below.

As an alternative, we propose the following modification to Criteria 2.12 to address TO control rooms that have the capability to perform monitoring and control of BES Transmission Lines while keeping the weighting proposed by the SDT (proposed language in bold + underline):

“Control Centers or backup Control Centers, not included in High Impact Rating above, that monitor and control BES Transmission Lines, or facilities hosting operating personnel that have the capability to monitor and control BES Transmission Lines, with an “aggregate

*weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. **The "aggregate weighted value" for a facility hosting operating personnel that has the capability to monitor and control BES Transmission Lines is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line that could be monitored and controlled by the facility hosting operating personnel."***

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The SDT explored using the text "hosting operating personnel" in the revision to Criterion 2.12, but determined that it could bring other Facilities into scope beyond Control Centers. For example, a substation that has relays that trip or close circuit breakers at multiple connected substations would then come into scope for Criterion 2.12 when operating personnel are present at the substation. Additionally, the SDT contends that Criterion 1.3 does not require conforming changes, since it clearly establishes the high categorization for BES Cyber Systems used by and located at Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10. After reviewing stakeholder comments, the SDT decided to revise Criterion 2.12 to remove ambiguity introduced by the monitor and control qualifiers. The SDT proposes removing "monitor and control" from the criterion and proposes inserting "used to perform the reliability tasks of the Transmission Operator". The SDT proposes the following text for Criterion 2.12., "Each Control Center or backup Control Center, not included in the High Impact Rating (H), used to perform the reliability tasks of the Transmission Operator in real-time for BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center." The SDT contends that the proposed revision clearly identifies medium impact BES Cyber Systems associated with Control Centers that perform the reliability tasks of the TOP.

Marty Hostler - Northern California Power Agency – 5

Answer

Document Name

Comment

NCPA is not a Transmission Operator and has No Comment.

Likes 0

Dislikes 0

Response

2. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

Southern Company would like specific clarification within the Standard text in section 5, “Effective Dates”. Southern asserts that the following text:

“By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.”,

should be changed to

“By that time, the Responsible Entity must apply all **CIP** Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.”

to provide this additional clarity.

We would also like the SDT to consider modifications to the language “capable of impacting the BES”. There are many aspects to commissioning assets that are complex and it is often such that it cannot be represented by a single date, but rather a series of steps across a period of time. The integration of new generation resources – especially Wind and to some extent Solar facilities – involves bringing blocks of generation on-line piecemeal, in many cases under local control with multiple vendors and contractors involved. During this transition period there are often temporary control measures in place and until the projects have been tested, integrated and transferred to the Control Center(s). It is the full intent to appropriately secure facilities under development in both physical and cyber aspects. Southern asserts that, at a *minimum*, the compliance effective date for new generation resources should be on the date it is declared “commercial” under its Interconnection Agreement.

Alternately, Southern proposes that if compliance must be met “upon commissioning,” then we request that this only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with all applicable CIP requirements “upon commissioning, as identified by the Responsible Entity.” This modification accommodates the complexity associated with the commissioning process and allows for the additional needed flexibility in commissioning different types of assets containing low impact BES Cyber Systems.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer

No

Document Name

Comment

PG&E believes the text of “capable of impacting the BES” will lead to interpretation differences between Entities and ERO Audit Teams due to the subjective nature of the text. Could the impact occur when; a) the BCS is initially installed, b) when it is being tested, c) after testing, or d) when it is placed into production?

With new BCS installations occurring months before actual production usage, the subjective nature of “capable of impacting” could subject an Entity to an extended period of potential violations if their interpretation is different than the Audit Teams. PG&E, as an active observer to the CIP Standard Drafting Team (SDT) meetings covering this modification, understands the difficulty in trying to create an unambiguous way to indicate when new BCS need to be covered by the CIP Requirements. PG&E’s suggested correction for this

condition is the creation of guidance, with examples of what would be considered “capable of impacting” for the different “asset” types in CIP-002. PG&E is willing to be part of the effort in drafting the guidance.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Andrea Barclay - Georgia System Operations Corporation – 4

Answer

No

Document Name

Comment

Unnecessarily Prescriptive:

We do not agree with the proposed modifications relating to “capable of impacting the BES.” This change from the v5 Implementation Plan is unnecessary and overly prescriptive. Specifically, the SDT has chosen to define “upon commissioning” without appreciating the complexity of commissioning or recognizing that commissioning is a process and not a point in time. The proposed change does not reflect the reality of cyber-physical systems. As defined in the NERC Glossary of Terms, the BES is comprised of Elements. These Elements include electrical devices such as “a generator, transformer, circuit breaker” etc. The BES Cyber Assets cannot be separated from the physical components that they control. As such, if a breaker is an Element and an Element is part of the BES, then there is no time at which the BES Cyber Asset is not “impacting the BES” since even though the circuit breaker switched out of service, it is still itself part of the BES. Ultimately, it appears that the changes proposed by the SDT in an attempt to provide clarity in certain circumstances, have inadvertently introduced unnecessary complexity and confusion into the commissioning process.

Alternative Proposal 1:

We propose that in place of the existing planned changes proposal that the SDT adopt the language as written in the version 5 Implementation Plan:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements” that contain periodic obligations as provided in the version 5 Implementation Plan.

Alternative Proposal 2:

If the SDT insists on requiring that compliance be met “upon commissioning,” then we request that this obligation only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with applicable periodic requirements within the first period following the commissioning as identified by the Responsible Entity, and with all other applicable requirements “upon commissioning as identified by the Responsible Entity.” This modification recognizes the complexity of the commissioning process and allows for flexibility since the commissioning process is not the same for different types of assets or different types of entities.

Likes	0
Dislikes	0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

sean erickson - Western Area Power Administration – 1

Answer	No
Document Name	

Comment

Clarifying planned and unplanned changes: they need to be more concise. The draft footnotes are too long and almost belong in the Glossary.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Gerry Adamski - Cogentrix Energy Power Management, LLC – 5

Answer

No

Document Name

Comment

As the Regions seem to arbitrarily define Planned or Unplanned Changes, various situations could create serious compliance issues, especially for generation entities.

An example of this would be purchase of generation assets and controlling those assets from a Low Impact Control Center. Incorporating the control of those assets may possibly change the impact classification of that Control Center to Medium or even possibly High. As the generation sector of our industry is seeing increased sale and purchase of generation facilities (especially in the private equity arena), as well as a decrease in the amount of time for sales and purchases to close, this proposed change would place an undue and unobtainable burden to have such a Control Center compliant to the new impact classification immediately upon acquisition.

Until there are clearly defined definitions of Planned and Unplanned Changes which are administered uniformly and address such situations as described above, we do not support this proposal.

I suggest that the proposed definition of Unplanned Change in footnote 2 of Page 4 be modified to include this scenario as subpart (5):

(5) A change in the classification of a Control Center per application of CIP-002, R1 and/or R2 caused by the purchase of a generating facility that is incorporated for control in that Control Center following its acquisition.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Marty Hostler - Northern California Power Agency – 5

Answer No

Document Name

Comment

No however I am willing to agree that all changes, regardless if Planned or Unplanned, should be treated equally. If Unplanned changes allow an entity two years to become compliant then NERC should not discriminate against those that have Planned changes. Both should be allowed two years to become compliant. Fairness!

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer No

Document Name

Comment

Propose including "and rely upon to perform reliability tasks."

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer No

Document Name

Comment

The phrase “...effective upon the date the new BES Cyber System is capable of impacting the BES.” is ambiguous and could lead to different interpretations of the “impact” date. An example would be when a new generator is being tested to validate it can sync to the grid before the BES Cyber System has been installed, tested, and placed in service. At this point in time, the generator can technically impact the BES, although in a non-substantive manner, but the generator owner will have coordinated with the RC/TOP/TP to make allowances for this testing and that the generator test run could end abruptly and accommodations are made to minimize any potential impacts. Dominion Energy suggests that the following language, used by SERC and published on their website, be used in place of the phrase: “Newly built Elements that are classified as BES Elements under the BES definition should be compliant prior to that Element being placed in service and added to the pool of BES Assets.”

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer

No

Document Name

Comment

As the Regions seem to arbitrarily define Planned or Unplanned Changes, various situations could create serious compliance issues, especially for generation entities.

An example of this would be purchase of generation assets and controlling those assets from a Low Impact Control Center. Incorporating the control of those assets may possibly change the impact classification of that Control Center to Medium or High. As the generation sector of our industry is seeing increased sale and purchase of generation facilities, as well as a decrease in the amount of time for sales

and purchases to close, this would place an undue and unobtainable burden to have such a Control Center compliant to the new impact classification.

Until there are clearly defined definitions of Planned and Unplanned Changes which are administered uniformly and address such situations as described above, we do not support this proposal.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer No

Document Name

Comment

The revision is likely to be interpreted that the categorization of a BES Cyber System will become effective when the BES Cyber System is part of generation that is first tied to the grid. This does not allow the entity to perform necessary testing and commissioning online during a time period when the BA understands that the generation associated with the new BES Cyber System is not yet reliable. During the time when the BA understands this generation to be unreliable due to further testing, the BA's function maintains grid reliability without dependence on the load from the generation associated with the new BES Cyber System.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

- Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.
- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.

- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. ...12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer

Yes

Document Name

Comment

“Please see comments submitted by the Edison Electric Institute”

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments.

Kenya Streeeter - Edison International - Southern California Edison Company – 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response Please see response to Edison Electric Institute’s comments.

Jamie Monette - Allete - Minnesota Power, Inc. – 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and

Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 2.

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute's comments for question 2.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

EI member companies generally support this change.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Document Name	
Comment	
No comment	
Likes	0
Dislikes	0
Response	
Anthony Jablonski - ReliabilityFirst – 10	
Answer	Yes
Document Name	
Comment	
Section A.5:	
<ol style="list-style-type: none"> 1. “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” This may be misleading in that the only “new” impact criterion in this version is 2.12. RF recommends the wording be changed to, “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets at least one criterion at a higher impact rating in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” 2. The language is not clear that it applies to a new asset coming into scope as a BES asset, and therefore will have new low impact BES Cyber Systems (LIBCS). As the Standard does not require identification of LIBCS, but only identification of the assets containing LIBCS, it’s not clear that the language “planned change resulting in a new BES Cyber System” and “planned change resulting in a 	

change in categorization for an existing BES Cyber System” will be effective in capturing new LIBCS. The language should directly address changes resulting in additional identified assets that contain LIBCS coming into scope for CIP-002. There are similar concerns for unplanned changes.

3. The language regarding initial performance of periodic obligations will result in very long lead times for some Requirements. For example, testing of an incident response plan for new low impact BES Cyber Systems (LIBCS) resulting from an unplanned change would not be required until 5 years after identification of the LIBCS. The initial performance of periodic requirements should be tightened to a more reasonable timeframe in order to reduce risk to the BES.

Section E is meant to incorporate the existing Interpretation. There are two problems with this:

1. The SDT did not fulfill the language of the NERC RoP regarding Interpretations: “The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.” [Standard Processes Manual, RoP Appendix 3A, Section 7] Since this revision of the Standard is an opportunity where the SDT can incorporate the Interpretation, it is incumbent upon the SDT to do so.
2. Placing the reference to the Interpretation in a section that is not identified by the Standard Processes Manual Section 2.5 may render the Interpretation unenforceable: “The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” [Standard Processes Manual, Section 2.5]

Likes 0

Dislikes 0

Response The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC – 1

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Trey Melcher - Lower Colorado River Authority – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority – 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Neville Bowen - Ocala Utility Services – 3	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Eric Smith - NaturEner USA, LLC – 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Becky Webb - Exelon – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Spencer Tacke - Modesto Irrigation District – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Boody - Lakeland Electric – 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Larry Watt - Lakeland Electric – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. – 4	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
<p>Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMMPA</p>	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
<p>Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns</p>	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0

Response

Pam Feuerstein - Intermountain REA – 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Zwergel - Midcontinent ISO, Inc. – 2

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. – 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Revnell - Wolverine Power Supply Cooperative, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy – 5

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority – 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Neil Swearingen - Salt River Project - 1,3,5,6 – WECC

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara – 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ginger Mercier - Prairie Power, Inc. - 1,3 – SERC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Effective Date Section: The SDT is proposing to clarify that for Planned Changes resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the responsible entity performs its review of identifications under Requirement R2, Part 2.1. Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF

Answer No

Document Name

Comment

NO, WE DO NOT ARGEE. Please see Consumers Energy response for question #2.

Likes 0

Dislikes 0

Response: Please see the SDT’s response to Consumer Energy for question 2.

Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF

Answer No

Document Name

Comment

As discussed in our answer to Question 2, arbitrary determinations of Planned and Unplanned Changes must be addressed across the regions.

Additionally, in some cases, where the region determines a planned change raises the impact from Low to Medium or High, the entity may be unable to meet all the requirements related to the new impact level, especially due to technical and resource limitations within the time period.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer

No

Document Name

Comment

Reclamation recommends the categorization of the BES Cyber System become effective upon the date the modified BES Cyber System is capable of impacting the BES. This will allow time for testing and returning existing equipment to service without the need to document compliance of equipment that is not capable of causing an adverse reliability impact.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-

002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Chinedu Ochonogor - APS - Arizona Public Service Co. – 6

Answer No

Document Name

Comment

While AZPS generally agrees with and supports the concepts regarding Planned Changes, it is concerned that the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” in the definition of a Planned Change could be interpreted more broadly than was intended and, therefore, impose an undue burden on Registered Entities.

More specifically, where a change is occurring that may impact a Responsible Entity’s asset identification, but that is not being planned or performed by that Responsible Entity, the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” assumes that such advance knowledge occurs far enough in advance of commercial operations for the impacted Responsible Entity to identify the impacts and implement compliance measures. Such notification is not within the control of the impacted Responsible Entity and the implementing party may not fully realize or understand the impacts of its Planned Change on adjacent systems or facilities.

For these reasons, a Responsible Entity may not have knowledge of such impacts far enough in advance of commercial operations to timely identify the impacts and implement the required compliance measures. More specifically, if a Responsible Entity received notification from an adjacent system or a project participant that modifications were being made six months prior to the commercial operation of such modification, the Responsible Entity, through no fault of its own, would likely have a reportable non-compliance as it would have “advance knowledge” of the “Planned Change,” but would not have enough time to identify impacts and implement compliance measures. Thus, in certain circumstances, the revisions to the concept of a Planned Change create an unrealistic or infeasible expectation. The definition of “Unplanned Changes” may be intended to cover this scenario, but the ambiguity of the language defining a “Planned Change” could lead to confusion and/or overlap. To rectify this, AZPS recommends the following revisions to sentence 1 of footnote 1:

Planned changes are changes to the Bulk Electric System or Cyber Asset(s) that were planned and implemented by the Responsible Entity or where the Responsible Entity received notification of such change from the implementing party at least 24 months prior to commercial operations.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

No

Document Name

Comment

Propose including "and rely upon to perform reliability tasks."

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Marty Hostler - Northern California Power Agency – 5	
Answer	No
Document Name	
Comment	
<p>No if the drafting team feels it is necessary to categorize more than every 15-months they should change that language in the standard. I don't recall NERC or the SAR requesting/authorizing this action.</p> <p>Additionally, IRC 2.1 and 2.11 are Impact Rating Criteria based on historical data. At least every 15-months an entity is to look back at the last 12-months of data and determine the Facilities' impact rating. If these Planned and Unplanned Change definitions are to go into effect then IRC 2.1 and 2.11 need to be excluded or deleted from the standard.</p>	
Dislikes 0	
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	
Gerry Adamski - Cogentrix Energy Power Management, LLC – 5	
Answer	No
Document Name	
Comment	

As discussed in our answer to Question 2, arbitrary determinations of Planned and Unplanned Changes must be addressed across the regions.

Additionally, in some cases, where the region determines a planned change raises the impact from Low to Medium or High, the entity may be unable to meet all the requirements related to the new impact level, especially due to technical and resource limitations within the time period.

I urge the drafting team to consider the addition of subpart 5 to the definition of Unplanned Change in footnote 2 on Page 4 of the standard:

(5) A change in the classification of a Control Center per application of CIP-002, R1 and/or R2 caused by the purchase of a generating facility that is incorporated for control in that Control Center following its acquisition.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

sean erickson - Western Area Power Administration – 1

Answer No

Document Name

Comment

Modifying Attachment 1 – Medium 2.1.2: while it is better to establish an MW value, it should be done across all High, Medium and Low. If MW value is going to be the risk bar, then let them revise Attachment 1 and simplify it.

Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. The SDT’s SAR addresses revisions to Criterion 2.12 to resolve the categorization of TO Control Centers performing the functional obligations of a TOP. The SDT has not been authorized to address the other criteria in Attachment 1. The SDT asserts that conforming changes are not required for the other criteria in Attachment 1.	
Spencer Tacke - Modesto Irrigation District – 4	
Answer	No
Document Name	
Comment	
Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.	
Andrea Barclay - Georgia System Operations Corporation – 4	
Answer	No

Document Name

Comment

Not consistent with CIP-002 R2.1:

We do not agree with the proposed modifications for Planned Changes resulting in a new BES Cyber System. BES Cyber Systems do not receive an impact rating except through performance of the process required in CIP-002 R1. CIP-002 itself recognizes that BES Cyber Systems only receive a rating upon the application of this process by specifically requiring that the identifications resulting from this process be reviewed and updated at least once every 15 calendar months (CIP-002 R2.1). If the application of CIP-002 R1 is in fact a continuous obligation, then there is no basis for CIP-002 R2, Part 2.1 to exist.

No Rationale for Modifications to Planned Changes:

Further, the SDT has provided no rationale for the modifications related to planned and unplanned changes. No Rationale Document has been developed and the summary in this informal comment form barely mentions this change even though it has a rippling impact across the entire suite of CIP standards.

Contradiction to V5 Implementation Plan:

The SDT appears to have taken it upon themselves to change the basis by which the CIP requirements become effective that was established in the CIPv5 implementation plan and existed prior to that in the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities (IPFNICCAANRE). In the IPFNICCAANRE, planned changes were classified as a category 3 scenario and specified to be “Compliant upon Commissioning.” Under the basis of version 3 where there were a limited number of Critical Assets and the standards themselves were specifically asset based, this approach was feasible. Additionally, version 3 of CIP-002 contained an obligation to update the CIP-002 list of Critical Cyber Assets “as needed.” Notably this obligation was removed in version 5. The version 5 Implementation Plan specifically says that “Planned changes refer to any changes of the electric system or BES Cyber System as identified through the annual assessment under CIP-002-5, Requirement R2, which were planned and implemented by the responsible entity.” The v5 implementation plan goes on to say that if a “modernization activity” is performed where Cyber Assets are installed that meet the criteria in CIP-002-5 Attachment 1, then the new Cyber Assets must be in compliance “upon the commissioning of the modernized transmission substation.” Notably in this scenario in order for the changes to have been identified under CIP-002 during the annual assessment, the transmission facility must have existed and had existing Cyber Assets at the time of the annual assessment. This example is no different than the execution of a recovery plan at an existing transmission substation. One would not argue that since a BES Cyber System failed and needed to be replaced that the replacement BES Cyber System would not need to be in

compliance until the next application of CIP-002. However, in the event that a facility or a BES Cyber System did not exist at the time of the annual CIP-002 assessment, then the cyber system has no assigned impact categorization and cannot be obligated to meet the suite of CIP requirements. Specifically, the v5 Implementation Plan goes on to state “For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the Version 5 CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System...” The SDT has provided no basis for changing this established expectation in its newly modified Effective Date “clarifying language.”

New Conflicting Language:

The SDT has introduced new conflicting language into the Effective Date section. The new language is conflicting as to when the initial performance of periodic requirements needs to be performed. Specifically, in section 5.1, the language states “By that time, the Responsible Entity must apply all Reliability Standard requirements applicable...” This specification of “all” does not indicate any exceptions. Three paragraphs later, the section states “For requirements that contain periodic obligations, initial performance of those new obligations...shall occur within the first period following the date the new BES Cyber System could adversely impact the BES.” These two statements conflict with each other. It is apparent that the SDT intended to provide additional time for periodic obligations. As such, it should not state that “all” requirements must be applied by the date if it intends to provide additional time for requirements with periodic obligations.

Alternative Proposal 1:

We propose that in place of the existing planned changes proposal that the SDT adopt the language as written in the version 5 Implementation Plan:

“For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements” that contain periodic obligations as provided in the version 5 Implementation Plan.

Alternative Proposal 2:

If the SDT insists on requiring that compliance be met “upon commissioning,” then we request that this obligation only apply to medium and high impact BES Cyber Systems and that the language state that the responsible entity shall comply with applicable periodic requirements within the first period following the commissioning as identified by the Responsible Entity, and with all other applicable requirements “upon commissioning as identified by the Responsible Entity.” This modification recognizes the complexity of

the commissioning process and allows for flexibility since the commissioning process is not the same for different types of assets or different types of entities.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer

No

Document Name

Comment

PG&E believes the text of “meets the new impact criteria in Attachment 1” will lead to interpretation differences between Entities and ERO Audit Teams due to the subjective nature of the text. Could the “meets the new impact criteria” occur when; a) the change happens on initial installation, b) during testing, c) after testing, or d) when finally placed into production?

Changes to existing facilities occur months before actual production usage and the subjective nature of “meets the new impact criteria in Attachment 1” could subject an Entity to an extended period of potential violations if their interpretation is different than the Audit Teams. PG&E, as an active observer to the CIP Standard Drafting Team (SDT) meetings covering this modification, understands the difficulty in trying to create an unambiguous way to indicate when changes to BCS require changes in the application of the CIP Requirements. PG&E’s suggested correction for this condition is the creation of guidance, with examples on what would be considered “meets the new impact criteria in Attachment 1” for the different “asset” types in CIP-002. PG&E is willing to be part of the effort in drafting the guidance.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

Southern does not agree with the proposed modifications for Planned Changes resulting in a new BES Cyber System. Until a BCS goes through the evaluation process required by CIP-002 R1, it does not have an impact rating. As such, if registered entities are to continually assess new assets, there is no real reason to have CIP-002 R2 part 2.1 as these required evaluations should have happened already, negating the need for a cycle.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst – 10	
Answer	Yes
Document Name	
Comment	
Section A.5:	
<ol style="list-style-type: none"> 1. “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” This may be misleading in that the only “new” impact criterion in this version is 2.12. RF recommends the wording be changed to, “[T]he categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets at least one criterion at a higher impact rating in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2[.]” 2. The language is not clear that it applies to a new asset coming into scope as a BES asset, and therefore will have new low impact BES Cyber Systems (LIBCS). As the Standard does not require identification of LIBCS, but only identification of the assets containing LIBCS, it’s not clear that the language “planned change resulting in a new BES Cyber System” and “planned change resulting in a change in categorization for an existing BES Cyber System” will be effective in capturing new LIBCS. The language should directly 	

address changes resulting in additional identified assets that contain LIBCS coming into scope for CIP-002. There are similar concerns for unplanned changes.

3. The language regarding initial performance of periodic obligations will result in very long lead times for some Requirements. For example, testing of an incident response plan for new low impact BES Cyber Systems (LIBCS) resulting from an unplanned change would not be required until 5 years after identification of the LIBCS. The initial performance of periodic requirements should be tightened to a more reasonable timeframe in order to reduce risk to the BES.

Section E is meant to incorporate the existing Interpretation. There are two problems with this:

1. The SDT did not fulfill the language of the NERC RoP regarding Interpretations: “The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.” [Standard Processes Manual, RoP Appendix 3A, Section 7] Since this revision of the Standard is an opportunity where the SDT can incorporate the Interpretation, it is incumbent upon the SDT to do so.
2. Placing the reference to the Interpretation in a section that is not identified by the Standard Processes Manual Section 2.5 may render the Interpretation unenforceable: “The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.” [Standard Processes Manual, Section 2.5]

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Leonard Kula - Independent Electricity System Operator – 2

Answer	Yes
Document Name	
Comment	
No comment	
Likes	0
Dislikes	0
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI member companies generally support this change.	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 3.	
Likes	0
Dislikes	0

Response: The SDT thanks you for your comments. Please see response to Edison Electric Institute's comments for question 3.

Jamie Monette - Allete - Minnesota Power, Inc. – 1

Answer	Yes
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes	0
Dislikes	0

Response: The SDT thanks you for your comments. Please see response to Edison Electric Institute's comments.

Kenya Streater - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comments. Please see response to Edison Electric Institute’s comments.	
Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comments. Please see response to Edison Electric Institute’s comments.	
Stacy Lee - City of College Station – 1	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Kjersti Drott - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginger Mercier - Prairie Power, Inc. - 1,3 – SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara – 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Thomas Savin - New York Power Authority – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Tim Womack - Puget Sound Energy, Inc. – 3	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Revnell - Wolverine Power Supply Cooperative, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nick Batty - Keys Energy Services – 4	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
David Zwergel - Midcontinent ISO, Inc. – 2	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. – 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Larry Watt - Lakeland Electric – 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Boody - Lakeland Electric – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Becky Webb - Exelon – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Eric Smith - NaturEner USA, LLC – 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neville Bowen - Ocala Utility Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Trey Melcher - Lower Colorado River Authority – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services – 3

Answer Yes

Document Name

Comment

Likes	0
Dislikes	0
Response	
LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	

4. Effective Date Section: Do you agree with the proposed modification to the unplanned changes section that provides 24 months for implementation of the requirements? If yes, please provide comments on why the timeframe is appropriate to assist the SDT with additional justification. If no, please provide your rationale and an alternate proposal.

Daniela Hammons - CenterPoint Energy Houston Electric, LLC – 1

Answer No

Document Name

Comment

Although 24 months may be a reasonable amount of time for some substation projects either planned or unplanned, others can take more than 24 months due to circumstances beyond control, such as:

- - Scheduling outages,
 - Substation resources already assigned to planned work that cannot be delayed,
 - Vendor issues.

An example is changing an asset that contains Low Impact BES Cyber Systems to an asset containing Medium Impact BES Cyber Systems with External Routable Connectivity (ERC) at an entity that previously did not have ERC at any substation. Designing, purchasing, installing, and testing both an Electronic Access Control and Monitoring System (EACMS) and Physical Access Control System (PACS) could easily take 24 months or more. Also, the number of requirement parts applicable to Medium Impact BES Cyber Systems with ERC is significantly more than that of those without ERC. The additional work involved with those additional requirements will equate to even more periodic work. Determining an approach to compliance, developing the new policies and procedures, and training could also take 24 months or more. The additional work may require hiring new staff.

CenterPoint Energy Houston Electric, LLC recommends adding language to the Effective Dates section that provides a method for which an entity can extend the time needed to complete an unplanned project when it is apparent that the project will take more than 24 months.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

Southern Company proposes the following modifications:

“For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective **30** calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all CIP Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until **30** calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following **a planned change** shall occur within the first period prescribed in the requirement, either 1) following the date the new BES Cyber System could adversely impact the BES, or 2) the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period prescribed in the requirement after **30** calendar months from the date of notification or detection of the unplanned change.”

Southern believes that “unplanned changes” should be handled equivalently as those in TPL-001-4 R2.7.3 where a situation outside the Planner’s control occurs and an unexpected Corrective Action Plan (CAP) is required. The TPL standard accepts some risk such as non-

consequential load loss until a CAP is in place. In the case of unplanned changes impacting compliance with the CIP Standards, a CAP or other plan could be developed and used to either proceed with increasing a facility's BES Cyber System(s) and associated BES Cyber Asset's impact classification to Medium Impact and moving to more CIP required controls, or alternatively to implement transmission system modifications (similar to segregating generating plant unit controls) that reduce risk and exposure by maintaining those BES Cyber System impact classifications at the low level. Southern requests the SDT consider and propose language allowing an Entity the flexibility to identify transmission improvements or system changes to remove or reduce the risk and exposure to the BES that accompanies unplanned changes, as well as provide the requisite time to make those improvements or changes that would help retain the associated BES Cyber Systems at a low impact classification rather than an Entity being required to enter into a long term financial and compliance burden if they were to rise from Low Impact to Medium Impact.

For example, the financial and compliance burden with having to comply with CIP Standards requirements applicable to Medium Impact BES Cyber Systems is tremendous, and can be compounded for an Entity in the event of unplanned changes that increase the impact classification of BES Cyber Systems. In those instances where an Entity chooses to make Transmission system improvements or modifications to keep applicable BES Cyber System in a Low Impact classification, but those improvements or changes will take 32 months to complete, from a risk-based perspective, what benefit or reduction of risk is provided should an entity have to make such a financial and organizational investment to comply with the CIP requirements applicable to Medium Impact BES Cyber Systems for only 2 months?

Southern requests the SDT consider that if a CAP or other plan developed as a result of an unplanned change includes steps to increase BES Cyber System impact ratings from Low Impact (or out of scope) to Medium Impact, the implementation time should be 30 months. This is an infrequent activity, but this time is warranted with the tremendous amount of Transmission work already being planned, and the additional time required to clarify notification/detection, scope of work, obtain budget dollars, schedule design disciplines, procure material, and complete construction for a very rare occurrence.

If a CAP or other plan is developed as a result of an unplanned change and is intended to include a transmission system modification, then more than 30 months may be needed to plan for and make the subsequent Transmission system modifications depending on the scope of the project. Southern recommends the SDT consider a process be available to Registered Entities to have the flexibility to implement a CAP or other plan that is shared with the ERO and tracked to completion as a mitigating measure for reducing BES exposure and risk by keeping BES Cyber System impact classifications at the Low Impact level.

For changes to BES Cyber System impact classifications associated with Control Centers, the compliance obligations for a Control Center containing Low Impact BES Cyber Systems compared to one that now has Medium Impact BES Cyber Systems as a result of an unplanned change are substantially different and greatly exceed the Low Impact requirements. For instance, should a Generation Owner decide to repower wind turbines and push a TOP's Control Center over 1500 MW, the TOP will have significant work to do upon notification from

the GO of this unplanned change. For such an unplanned change, 30 months is warranted in order for the TOP to meet the financial and compliance burdens of having a BES Cyber System(s) with increased impact classifications.

In each of the examples above, Southern asserts that the requested 30 months will allow for a more thorough review of all potential solutions.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Andrea Barclay - Georgia System Operations Corporation – 4

Answer

No

Document Name

Comment

For the reasons outlined in questions 2 and 3, we also do not agree with the 24 months for implementation of unplanned changes. In particular, we believe that the SDT should adopt the language included in the Version 5 Implementation Plan that states “For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements...according to the following timelines, following the identification and categorization of the affected BES Cyber System.” This language necessarily recognizes that all timeframes for CIP-002 start with the performance of the annual CIP-002 process.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer No

Document Name

Comment

While Texas RE appreciates timeframes around planned and unplanned changes, the language is vague and will cause confusion. The Implementation Plan and the Effective Date section should work together. Texas RE recommends using the verbiage from the Implementation Plan rather than the use of the new term “first period” from the Effective Date section. This appears to be the first time this term has been used in the context of effective dates and with no explanation, there could be confusion as to when and how long the first period is.

The Implementation Plan, on the other hand, states: Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a. Texas RE prefers this verbiage than the “first period” term as it is more clear and would be consistent with how Implementation Plans have been written in the past.

Additionally, Texas RE suggests defining planned and unplanned changes to reduce ambiguity and vagueness. Texas RE recommends that entities have 24 months from the identification of a change. As written, it is unclear how long in the future a change is known could be considered an unplanned change. For example, Footnote 2, example 1, points to Criterion 2.3 which states planning horizon of more than a year. If it is under a year, do entities have 24 months to come into compliance? If it is over a year, do entities get 24 months from that date to come into compliance? If unplanned asset is identified as coming after 24 months, it should be treated as planned. In example 4, entities should know far in advance whether there will be additional load. How far in advance is considered planned?

Likes 0

Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	
<p>Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6</p>	
Answer	No
Document Name	
<p>Comment</p>	
<p>24 months would not allow for the time necessary to get required budget and implementation required. IID is recommending that 36 months would be a more adequate time to fund and implement necessary requirements.</p>	
Likes	0
Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	
<p>Marty Hostler - Northern California Power Agency – 5</p>	
Answer	No
Document Name	

Comment

No however I am willing to agree that all changes, regardless if Planned or Unplanned, should be treated equally. If Unplanned changes allow an entity two years to become compliant then NERC should not discriminate against those that have Planned changes. Both should be allowed two years to become compliant. Fairness!

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Anthony Jablonski - ReliabilityFirst – 10

Answer

No

Document Name

Comment

The proposed timeframe is not in line with prior practice. 12 months has been prior practice. RF is not aware of any entity having difficulty with this timeframe.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-

002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer No

Document Name

Comment

The proposed implementation timeline for a large facility such as a generator moving from a Low to Medium Impact could take substantially more time than 24 calendar months. Recommend increasing the timeline to 36 calendar months. Suggest the SDT tie the implementation timeline to the size of the asset or number of Cyber Systems associated with the asset. This is probably not a “one size fits all”.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer Yes

Document Name

Comment

“Please see comments submitted by the Edison Electric Institute”

Likes 0

Dislikes 0

Response: Please see the SDT response to Edison Electric Institute’s comments.

Kenya Streeter - Edison International - Southern California Edison Company – 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response: Please see the SDT response to Edison Electric Institute’s comments.

Jamie Monette - Allete - Minnesota Power, Inc. – 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response: Please see the SDT response to Edison Electric Institute’s comments.

David Jendras - Ameren - Ameren Services – 3

Answer Yes

Document Name

Comment

Ameren agrees with the EEI in response to this question.

Likes 0

Dislikes 0

Response: Please see the SDT response to Edison Electric Institute’s comments.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson

Answer Yes

Document Name

Comment

PG&E believes the 24 month time-frame is sufficient to apply the necessary Requirement changes when the impact rating goes from low to medium, or medium to high. While PG&E has not experienced changes in impact rating that would elevate a BCS impact rating, our experience on the application of the Requirements for medium and high BCS does not suggest a longer time-frame would be necessary.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various

industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Constantin Chitescu - Ontario Power Generation Inc. – 5

Answer Yes

Document Name

Comment

OPG concurs with the RSC comment.

Likes 0

Dislikes 0

Response: Please see the SDT's response to the RSC's comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 4.

Likes 0

Dislikes	0
Response: Please reference the SDT's response to Edison Electric Institute's comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
<p>EEI member companies support the SDT's proposed 24-month implementation period for unplanned changes. Unplanned changes can have significant impacts on internal company processes and associated capital budgets, which can take as long as 12 months for approval before the funds can be allocated. We also note that unplanned changes, including recategorizing of control centers from Low Impact to Medium Impact, represent a major effort that places substantial demands on scarce technical resources. Moreover, a 24-month Implementation period is not without Industry precedent for compliance with substantial changes involving CIP Standards. In FERC Order 791 (Ref. 145 FERC 61,160; Docket No. RM13-5-000: Version 5 Critical Infrastructure Protection Standards; Issued November 22, 2013) the Industry was afforded a 24-month implementation period to ensure entity compliance was achieved for High and Medium Impact BES Cyber Systems. While we recognize that the transition to CIP Version 5 was a significant Industry effort, the efforts to transition a control center (worst case) from Low Impact to Medium Impact could represent similar challenges for entities that only have Low Impact BES Cyber Systems.</p>	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.	

Patricia Boody - Lakeland Electric – 3

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

We support the comments provided by the FMPA:

We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn't seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*** This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0	
---------	--

Dislikes 0	
------------	--

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Larry Watt - Lakeland Electric – 1

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

Comments: We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn't seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*** This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA

Answer

Yes

Document Name

Comment

We agree with the 24 months for implementation but are concerned about potential issues surrounding Attachment 1, Criterion 2.6. The concern is if a facility has an IROL that only lasts for 18 months, will the entity that owns that facility be required to have Medium Impact controls? It doesn't seem to make sense if the IROL is less than, or even just barely more than, the implementation time-period to require Medium Impact controls. Our suggestion would be to add the following language to Attachment 1, Criterion 2.6: *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies for a time-period greater than 36 months.*** This helps to avoid a situation where a utility would have the costly requirement to add Medium Impact controls to a facility that has a temporary IROL or an IROL that will be mitigated and not exist after the 24 month implementation period.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Leonard Kula - Independent Electricity System Operator – 2

Answer Yes

Document Name

Comment

No comment

Likes 0

Dislikes 0

Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
<p>ITC concurs with comments submitted by EEI:</p> <p>"EEI member companies support the SDT's proposed 24-month implementation period for unplanned changes. Unplanned changes can have significant impacts on internal company processes and associated capital budgets, which can take as long as 12 months for approval before the funds can be allocated. We also note that unplanned changes, including recategorizing of control centers from Low Impact to Medium Impact, represent a major effort that places substantial demands on scarce technical resources. Moreover, a 24-month Implementation period is not without Industry precedent for compliance with substantial changes involving CIP Standards. In FERC Order 791 (Ref. 145 FERC 61,160; Docket No. RM13-5-000: Version 5 Critical Infrastructure Protection Standards; Issued November 22, 2013) the Industry was afforded a 24-month implementation period to ensure entity compliance was achieved for High and Medium Impact BES Cyber Systems. While we recognize that the transition to CIP Version 5 was a significant Industry effort, the efforts to transition a control center (worst case) from Low Impact to Medium Impact could represent similar challenges for entities that only have Low Impact BES Cyber Systems."</p>	
Likes	0
Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed	
Answer	Yes
Document Name	
Comment	
We agree with 24 months for the implementation of requirements for unplanned changes. Unplanned changes can have significant impacts and place substantial demands on technical resources, depending upon the scope of the unplanned changes.	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.	
David Zwergel - Midcontinent ISO, Inc. – 2	
Answer	Yes
Document Name	
Comment	
Example: The compliance obligations for a Medium Impact Control Center are substantial and greatly exceed the Low Impact requirements. One can easily envision a GO repowering wind turbines and pushing a TOP’s Control Center over 1500 MW (Criteria 2.11 and 2.13). Assuming each is a different Responsible Entity, the TOP will have significant work to do upon notification from the GO of this unplanned change.	

Likes	0
Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	
<p>Gerry Adamski - Cogentrix Energy Power Management, LLC – 5</p>	
Answer	Yes
Document Name	
<p>Comment</p>	
<p>The entity has no prior expectation for implementing either Medium or High Impact requirements prior to the notification from the Planning Coordinator or Transmission Planner or Reliability Coordinator, etc. or that a parent organization has purchased a generating facility that is now being placed under your control in an existing Control Center. In this regard, it is unrealistic for the entity to coordinate and implement an effective and robust CIP program in a rushed manner. Furthermore, cyber assets need to be specified, ordered, configured, and installed, training programs developed after a full suite of procedures are drafted, and above all, a secure network infrastructure created to protect the most important cyber assets. These activities presume funding is made available for an unbudgeted project in the current year. On the whole, a project of this type requires at least a year for a thoughtful specification, budgeting, and implementation. So the 24 months proposal is entirely adequate.</p>	
Likes	0
Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-</p>	

002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer Yes

Document Name

Comment

The 24-month timeframe is appropriate because it is commensurate with the initial implementation plan of CIP-002-5.1a. The 24-month timeframe allows sufficient time for entities to implement compliance measures for changes that the entity did not originally have scoped for compliance (e.g., budget cycles, procurement timeframes, and documentation).

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes	0
Dislikes	0
Response: Please reference the SDT's response to the MRO NSRF.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
<p>Example: The compliance obligations for a Medium Impact Control Center are substantial and greatly exceed the Low Impact requirements. One can easily envision a GO repowering wind turbines and pushing a TOP's Control Center over 1500 MW (Criteria 2.11 and 2.13). Assuming each is a different Responsible Entity, the TOP will have significant work to do upon notification from the GO of this unplanned change.</p>	
Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	

None	
Likes	0
Dislikes	0
Response	
Leanna Lamatrice - AEP – 3	
Answer	Yes
Document Name	
Comment	
<p>AEP supports the proposed modification to the unplanned changes section that provides 24 months for the implementation of the requirements. AEP feels this would provide sufficient time to accomplish all the physical changes necessary to move from compliance for an asset containing low impact BES Cyber Systems to one where all the BES Cyber Systems are instantly categorized as medium.</p>	
Likes	0
Dislikes	0
<p>Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.</p>	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF	
Answer	Yes
Document Name	

Comment

24 months should provide a Responsible Entity with enough time to implement all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber Systems due to unplanned changes.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Ginger Mercier - Prairie Power, Inc. - 1,3 – SERC

Answer Yes

Document Name

Comment

Yes. 24 months should be adequate in most cases.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Trey Melcher - Lower Colorado River Authority – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Teresa Cantwell - Lower Colorado River Authority – 5	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. – 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neville Bowen - Ocala Utility Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Becky Webb - Exelon – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Spencer Tacke - Modesto Irrigation District – 4	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
sean erickson - Western Area Power Administration – 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chinedu Ochonogor - APS - Arizona Public Service Co. – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Revnell - Wolverine Power Supply Cooperative, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington – 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Womack - Puget Sound Energy, Inc. – 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Thomas Savin - New York Power Authority – 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Bruce Reimer - Manitoba Hydro – 1	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. – 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Implementation Plan: The SDT modified the Implementation Plan. Do you agree with the proposed Implementation Plan?

a. If yes, please provide comments on why the timeframes are appropriate to assist the SDT with additional justification.

b. If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF

Answer No

Document Name

Comment

To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is **twenty-four (24) calendar months** after the effective date of the applicable governmental authority’s order approving the standard.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	
Comment	
<p>Either the implementation timeline needs to be increased or the Implementation Plan for the effective date of the standard needs to be increased.</p>	
Likes 0	
Dislikes 0	
<p>Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.</p>	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	No
Document Name	
Comment	
<p>Reclamation recommends the following changes to the proposed implementation plan:</p> <p>Initial Performance of Periodic Requirements - Reclamation recommends CIP-002-6 become effective no earlier than 24 months after the applicable governmental entity’s order approving the standard to allow entities flexibility to determine the appropriate implementation.</p>	

Reclamation agrees with the Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12. A longer implementation period may be needed if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System.

Reclamation agrees that any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.

Reclamation agrees that Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Marty Hostler - Northern California Power Agency – 5

Answer No

Document Name

Comment

No. I am willing to agree to have Transmission Owners that have been inadvertently categorized as medium impact allowed to immediately be recategorized to low impact. Two-years should be the standard implementation time frame for the rest of the industry if

their rating is to increase. Also I thought the STB was suppose to redefine Control Centers, we had alot of discussion but I don't recall seeing any results.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3. The SDT determined that the proposed revisions to Criterion 2.12 satisfy the TO Control Center issue assigned in the SAR for this project. The SDT asserts that revisions to the Control Center definition could have an impact on the operations and planning standards that use the defined term and has decided not to revise the defined term at this time.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer No

Document Name

Comment

IID is proposing a 12 month effective date after approval due to budget needs if an impact rating on facility were to change.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard.

This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Spencer Tacke - Modesto Irrigation District – 4

Answer No

Document Name

Comment

Transmission Line Impact Criteria should be based on the Short Circuit MVA (6,000 MVA or greater) , and not on arbitrary weighting factors.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. In CIP-002-5.1a, Attachment 1, Criterion 2.5, the total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines. The values were established in NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index.” The SDT used the 3,000 weighted value from Criterion 2.5 to establish the maximum weighted value for low impact BES Cyber Systems associated with a single Transmission station or substation. The SDT doubled 3000 in order to establish a 6000 aggregate weighted value because an applicable Control Center operates transmission Facilities at two or more locations. This establishes the "floor" for medium impact BES Cyber Systems associated with a Control Center that monitors and controls Transmission Lines.

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer	No
Document Name	
Comment	
<p>Texas RE has two main concerns with the Implementation Plan as written: planned and unplanned changes, and the retirement of CIP-002-5.1a. Regarding the first matter, the Implementation Plan has this statement: “Planned or Unplanned Changes Any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.” Since planned and unplanned changes are mentioned in other Reliability Standards, Texas RE is concerned of the implications of this statement. For example, CIP-013-1 has planned and unplanned changes referenced with exact timelines: “For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-005-6, CIP-010-3, and CIP-013-1 on the update of the identification and categorization of the affected BES Cyber System.</p> <p>For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-005-6, CIP-010-3, and CIP-013-1 according to a specific timeline, following the identification and categorization of the affected BES Cyber System. The unplanned timelines for FERC approved CIP-013-1 are different from those proposed in CIP-002-6. The Implementation Plan for CIP-002-6 should not affect the Implementation Plan for CIP-013-1, since CIP-013-1 is approved by FERC.</p> <p>Alternatively, the SDT could embark on a project to define planned and unplanned changes in the NERC Glossary as suggested in Texas RE’s comment to #4. This would include an analysis to determine which standards currently use those terms and how those terms are used. Having a clear definition would reduce the ambiguity and vagueness of those terms.</p> <p>Second, the Implementation Plan contains the following statement regarding the phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12: “If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.” Since CIP-002-5.1a is being proposed to be retired immediately prior to the effective date of CIP-002-6, Texas RE is concerned there may be a gap in that 24 month time period.</p>	
Likes	0
Dislikes	0

Response The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Andrea Barclay - Georgia System Operations Corporation – 4

Answer	No
---------------	----

Document Name	
----------------------	--

Comment

We do not believe that the revisions in CIP-002 can be implemented “immediately” following FERC approval. In order to demonstrate compliance with CIP-002, responsible entities have been expected to provide evidence of the consideration and application of each and every criterion in Attachment 1 even when they do not change the impact categorization of any BES Cyber Systems. The modifications to criterion 2.12 are substantial. Even in the case where the newly modified criteria does not change the categorization of any BES Cyber Systems, time is needed in order to assess the new criterion and apply it against our systems. Additionally, time is needed to update process documentation. The Implementation Plan provides a 24 month implementation interval where the

modified criterion increases the impact rating of a BES Cyber System. We recommend that the same length of time be provided to all responsible entities.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This could re-categorize some entity’s BES Cyber Systems as low impact (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3. Additionally, the implementation plan requires entities to initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a. This allows entities to maintain their current CIP-002 annual review cycle.

Teresa Cantwell - Lower Colorado River Authority – 5

Answer No

Document Name

Comment

Entities should identify the facility according to CIP-002-6 criteria, and not go back to CIP-002-5.1a. Their documentation needs to provide if a higher categorization was determined, along with the date, and if it is planned or unplanned. Otherwise, there is more room for confusion and compliance risks.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This could re-categorize some entity’s BES Cyber Systems as low impact (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3. Additionally, the implementation plan requires entities to initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

Southern Company asserts that the 30-month timeframe is needed for a significant change such as a Control Center containing Low Impact BES Cyber Systems being reclassified as having Medium Impact BES Cyber Systems. Southern requests the SDT propose a 30-month implementation period, rather than 24 months, to align with the following proposed edits:

“...medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6...”

to

“...medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until **30** months after the effective date of CIP-002-6...”.

For entities who only currently have Low Impact Control Centers, maintaining compliance throughout the transition and beyond would require a substantial increase in budget allocation, manpower and planning, all of which take time.

Likes	0
Dislikes	0
Response: The SDT thanks you for your comments. Twenty-four months was selected by the SDT to give entities time to budget for and implement modifications required for a change in BES Cyber System categorization. The SDT asserts that 24 months is an appropriate amount of time to implement the required CIP Standards and associated requirements.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC – 1	
Answer	No
Document Name	
Comment	
Please see response to Question 4.	
Likes	0
Dislikes	0
Response: Please see response to Question 4.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes	0
Dislikes	0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Medium Impact compliance obligations greatly exceed those for Low Impact, with Control Centers being the most extreme case. The time allotted for meeting these obligations needs to be sufficient, especially for any Responsible Entities not previously required to comply with CIP-004 through CIP-011.

The proposed 24 months is consistent with the implementation plan passed for CIP-003 through CIP-009 version 2 and 3 standards for Responsible Entities in Category 1 that had not previously identified Critical Cyber Assets and thus had no previous exposure to these standards.

Given the addition since then of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.

Likes 0

Dislikes 0

Response The SDT thanks you for your comments. Twenty-four months was selected by the SDT to give entities time to budget for and implement modifications required for a change in BES Cyber System categorization. The SDT asserts that 24 months is an appropriate amount of time to implement the required CIP Standards and associated requirements.

Bruce Reimer - Manitoba Hydro - 1

Answer Yes

Document Name

Comment

We think completing compliance tasks within 24 months is a reasonable timeframe for the revisions to Criterion 2.12 resulting in a higher impact level categorization of a BES Cyber System (from low impact to medium impact).

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Please refer to comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

Response Please see the response for MRO NSRF.

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer Yes

Document Name

Comment

The proposed timeframe aligns with the 15 calendr month cycle in CIP-002-5.1a R2.

Likes 0

Dislikes	0
Response The SDT thanks you for your comments.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The proposed timeframes are consistent with good business practice and with good security practice.	
Likes	0
Dislikes	0
Response The SDT thanks you for your comments.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Please see response to Q4.	
Likes	0
Dislikes	0
Response Please see response to Q4.	
David Zwergel - Midcontinent ISO, Inc. - 2	

Answer	Yes
Document Name	
Comment	
<p>Medium Impact compliance obligations greatly exceed those for Low Impact, with Control Centers being the most extreme case. The time allotted for meeting these obligations needs to be sufficient, especially for any Responsible Entities not previously required to comply with CIP-004 through CIP-011.</p> <p>The proposed 24 months is consistent with the implementation plan passed for CIP-003 through CIP-009 version 2 and 3 standards for Responsible Entities in Category 1 that had not previously identified Critical Cyber Assets and thus had no previous exposure to these standards.</p> <p>Given the addition since then of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.</p>	
Likes 0	
Dislikes 0	
<p>Response The SDT thanks you for your comments. Twenty-four months was selected by the SDT to give entities time to budget for and implement modifications required for a change in BES Cyber System categorization. The SDT asserts that 24 months is an appropriate amount of time to implement the required CIP Standards and associated requirements.</p>	
<p>Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion annd Con Ed</p>	
Answer	Yes
Document Name	
Comment	
<p>We like the Implementation Plan as is.</p>	

We agree with 24 months for the implementation of requirements for unplanned changes. Unplanned changes can have significant impacts and place substantial demands on technical resources, depending upon the scope of the unplanned changes.

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer Yes

Document Name

Comment

ITC concurs with comments submitted by EEI:

"EEI member companies support the timeframes provided within the SDT's Implementation Plan and believe that the time allocated is necessary due to substantial company efforts necessary for transitioning from a Low Impact to Medium Impact. A more detailed explanation of why we feel a 24-month implementation period for unplanned changes is necessary is provided in our response to question 4 (above)."

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

IESO agrees with the proposed Implementation Plan (a)

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer

Yes

Document Name

Comment

Given the addition of standards CIP-010, CIP-011, and upcoming CIP-013, and that Responsible Entities will likely have to wait until their next fiscal year to budget for any needed equipment and additional personnel, 36 months may be more appropriate.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, if the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Twenty-four months was selected by the SDT to give entities time to budget for and implement modifications required for a change in BES Cyber System categorization. The SDT asserts that 24 months is an appropriate amount of time to implement the required CIP Standards and associated requirements.

sean erickson - Western Area Power Administration - 1

Answer Yes

Document Name

Comment

no comment

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

EI member companies support the timeframes provided within the SDT's Implementation Plan and believe that the time allocated is necessary due to substantial company efforts necessary for transitioning from a Low Impact to Medium Impact. A more detailed explanation of why we feel a 24-month implementation period for unplanned changes is necessary is provided in our response to question 4 (above).

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 5.

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

It is an appropriate timeframe to implement.

Likes 0

Dislikes 0

Response The SDT thanks you for your comments.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG concurs with the RSC comment.	
Likes	0
Dislikes	0
Response The SDT thanks you for your comments.	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
<p>1) The immediate nature of the effective date will allow those Entities with medium impact Transmission Control Centers that in reality should have been designated as low impact, immediate relief, with the ability to appropriately adjust their programs.</p> <p>2) The phased in implementation of 24 months for conditions resulting in a higher impact rating (low to medium) is sufficient based on PG&E experiences.</p> <p>3) The inclusion of the “planned” and “unplanned” conditions within CIP-002-6 is a welcomed improvement over the separate document used with the original CIP Version 5 Standards.</p>	
Likes	0
Dislikes	0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Ameren agrees with the EEI in response to this question.

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute's comments.

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer Yes

Document Name

Comment

Minnesota Power supports EEI's comments.

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer Yes

Document Name

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments.

Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6

Answer Yes

Document Name

Comment

“Please see comments submitted by the Edison Electric Institute”

Likes 0

Dislikes 0

Response: Please see response to Edison Electric Institute’s comments

Stacy Lee - City of College Station - 1

Answer Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ginger Mercier - Prairie Power, Inc. - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Sandra Revnell - Wolverine Power Supply Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA	
Answer	Yes
Document Name	
Comment	

Likes	0
Dislikes	0
Response	
Larry Watt - Lakeland Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Patricia Boody - Lakeland Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Becky Webb - Exelon – 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neville Bowen - Ocala Utility Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Street - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Trey Melcher - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

6. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer No

Document Name

Comment

The proposed modifications to CIP-002 will substantially increase the cost of compliance and represent an undue burden to registered entities as proposed. They stand to change what is currently a periodic requirement to a real-time requirement.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Andrea Barclay - Georgia System Operations Corporation - 4

Answer No

Document Name

Comment

No, the proposed modifications substantially increase the cost of compliance over prior versions of the standard as they introduce unjustified and undirected modifications that substantially increase the burden of compliance from an annual obligation to an ongoing real-time obligation. We propose instead that the SDT adopt the language in the existing approved Version 5 Implementation Plan.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

sean erickson - Western Area Power Administration – 1

Answer

No

Document Name

Comment

Minor changes such as these tend to reverberate and translate into more work for entity's to ingest, coordinate and respond

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-

002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Marty Hostler - Northern California Power Agency – 5

Answer No

Document Name

Comment

No however I am will to agree that all changes regardless if Planned or Unplanned should be treated equally. I don't believe any of the new Planned and Unplanned Changes language is necessary. Additionally, I don't believe the proposal is cost effective or necessary. An agreement with Transmission Operators should have been negotiated.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Chinedu Ochonogor - APS - Arizona Public Service Co. – 6

Answer No

Document Name

Comment

As expressed in AZPS’s response to Question 3 above, AZPS is concerned that the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” in the definition of a Planned Change could be interpreted more broadly than was intended and, therefore, impose an undue burden on Registered Entities. More specifically, where a change is occurring that may impact a Responsible Entity’s asset identification, but that is not being planned or performed by that Responsible Entity, the inclusion of the phrase “or with the Responsible Entity’s advance knowledge” assumes that such advance knowledge occurs far enough in advance of commercial operations for the impacted Responsible Entity to identify the impacts and implement compliance measures. Such notification is not within the control of the impacted Responsible Entity and the implementing party may not fully realize or understand the impacts of its Planned Change on adjacent systems or facilities. For these reasons, a Responsible Entity may not have knowledge of such impacts far enough in advance of commercial operations to implement the required compliance measures in a cost effective manner.

If AZPS’s recommended revisions for Question 3 above are incorporated into the standard, AZPS would agree that the proposed modifications provide entities with flexibility to meet the reliability objectives in a cost effective manner.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer

No

Document Name

Comment

Reclamation recommends the simplified Impact Rating Criteria described in the response to Question 1 will provide a more cost-effective manner of categorizing BES Cyber Systems and their associated BES Cyber Assets by reducing the cost of implementing the standard and the overall impact of CIP-002-6 and allowing entities to reduce the time spent “review[ing] the identifications in Requirement R1 and its parts (and update[ing] them if there are changes identified) at least once every 15 calendar months.”

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. The effective date in the proposed implementation plan is the first day of the first calendar quarter that is immediately after the effective date of the applicable governmental authority’s order approving the standard. This implementation period was proposed by the SDT to provide entities the opportunity to reevaluate their BES Cyber Systems immediately with the revisions to Criterion 2.12. This would allow entities to re-categorize BES Cyber Systems as low impact, pursuant to proposed Criterion 2.12 (from medium impact to low impact). However, If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer

No

Document Name

Comment

The language currently being proposed and commented upon in Q2 above is implemented, it could result in inefficient and expensive changes to the generator commissioning process.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer No

Document Name

Comment

See comment on item 2.

Likes 0

Dislikes 0

Response: Please see the SDT's response to question 2.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 – RF

Answer No

Document Name

Comment

NO, WE DO NOT ARGEE. Please see Consumers Energy response for question #2.

Likes 0

Dislikes	0
Response: Please see the SDT's response to question 2.	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes	0
Dislikes	0
Response:	
Ayman Samaan - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes	0
Dislikes	0
Response: Please reference the SDT's response to Edison Electric Institute.	
Kenya Streeter - Edison International - Southern California Edison Company – 6	
Answer	Yes

Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response: Please reference the SDT's response to Edison Electric Institute.	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 5, 1, 3; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
<p>PG&E believes the modifications do provide sufficient flexibility in meeting the reliability objectives, but as noted in Questions 2 and 3, the subjective nature of “impact to the BES” and “meets the new impact criteria” needs to be addressed before final approval of the modifications.</p> <p>In addition to the comments provided in Questions 2 and 3, the use of “adversely impact the BES” and “the date the existing BES Cyber System meets the new impact criteria in Attachment 1” in the last paragraph of Section 5.1 on PDF page 2 have the same condition PG&E has noted for Questions 2 and 3. The subjective nature of that text, will lead to differences in interpretations exposing an Entity to potential non-compliance. As suggested in Questions 2 and 3, PG&E believes the creation of guidance, with examples on what would be considered “capable of impacting” which is the same as “adversely impact the BES” and “date the existing BES Cyber System meets the new impact criteria” for the different “asset” types in CIP-002 would help alleviate this condition. PG&E also reiterates the statements in Questions 2 and 3 that they are willing to help in the drafting of that guidance.</p>	
Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

We thank the SDT for allowing us to provide comments on these standards.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar and Kansas City Power & Light Co. support and incorporate by reference Edison Electric Institute's response to Question 6.

Likes 0

Dislikes 0

Response: Please reference the SDT's response to Edison Electric Institute.

Gerry Adamski - Cogentrix Energy Power Management, LLC – 5

Answer

Yes

Document Name

Comment

Yes if the definition of Unplanned Changes incorporates the suggested change for including a newly purchased generating facility being added to a Low Impact Control Center, which results in an elevated classification. See reply to Q2 and Q3.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Upon reviewing the industry comments on the Planned and Unplanned changes section, several issues were raised. Among those are the need to reconcile the timeframes inherent in the language with CIP-002 R2 and some of the criteria in CIP-002 Attachment 1, along with reconciliation with aspects of CIP-013. As the SDT considered the various industry comments, it became apparent that the periodicity of the CIP-002 process is a larger issue that may require changes to CIP-002 that are not within our SAR. The SDT plans to revert the planned/unplanned changes back to current state and will be drafting a SAR to address the need for further clarity on this issue.

Ginger Mercier - Prairie Power, Inc. - 1,3 – SERC

Answer

Yes

Document Name

Comment

PPI agrees with WECC's comment to include a provision to allow for early TO adoption to reclassify TOCCs as low-impact under the revised Impact Rating Criteria 2.12.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. Please see the implementation plan for the phased in approach for criterion 2.12.

Steven Rueckert - Western Electricity Coordinating Council – 10

Answer Yes

Document Name

Comment

Although WECC agrees with the proposed modifications to CIP-002-6, some TO entities may wish to move sooner to reclassify their TOCCs as low impact BES Assets under the revised Impact Rating Criterion 2.12. A provision should be made to allow for such early adopters, as WECC recognizes the minimal risk to the reliability and security of the BES by such a reclassification to a lower risk BCS category.

Likes 1 Prairie Power, Inc., 1,3, Mercier Ginger

Dislikes 0

Response: The SDT thanks you for your comments. Please see the implementation plan for the phased in approach for criterion 2.12.

LaTroy Brumfield - American Transmission Company, LLC – 1

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Trey Melcher - Lower Colorado River Authority – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patrick Wells - OGE Energy - Oklahoma Gas and Electric Co. – 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neville Bowen - Ocala Utility Services – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Becky Webb - Exelon – 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District – 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Patricia Boody - Lakeland Electric – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. – 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 5, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Zwergel - Midcontinent ISO, Inc. – 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst – 10

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Revnell - Wolverine Power Supply Cooperative, Inc. – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington – 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Snow - Cogentrix Energy Power Management, LLC - 5 - NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro – 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. – 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara – 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Leanna Lamatrice - AEP – 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kjersti Drott - Tri-State G and T Association, Inc. – 1

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	
Document Name	
Comment	
Minnesota Power will abstain from voting on this issue.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services – 3

Answer

Document Name

Comment

Ameren will remain silent on this matter.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer

Document Name

Comment

Texas RE does not have comments on this question.

Likes 0

Dislikes 0

Response

End of Report

Standards Announcement

Reminder

Project 2016-02 Modifications to CIP Standards

Additional Ballot and Non-binding Polls Open through July 17, 2019

[Now Available](#)

The additional ballot and non-binding Poll for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Wednesday, July 17, 2019**.

Balloting

Members of the ballot pools associated with this project can log in to the [Standards Balloting and Commenting System \(SBS\)](#) and submit their votes. Contact [Wendy Muller](#) regarding issues using the SBS.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Note: If a member cast a vote in the previous ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through July 17, 2019

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Wednesday, July 17, 2019**.

A version of CIP-002-6 was posted for ballot September 28 through October 9, 2018, that included modifications to criteria 2.6 and 2.9 based on the work of the [Project 2015-09 Establish and Communicate System Operating Limits](#) standard drafting team. The Project 2016-02 Modifications to CIP Standards and Project 2015-09 standard drafting teams determined that these revisions are no longer needed at this time. As a result, CIP-002-6 will be posted for an additional comment and ballot period without the revisions to criteria 2.6 and 2.9. NERC will reopen the ballot pool to accommodate changes in the ballot body.

Ballot Pools

Registered Ballot Body members can join the ballot pools in the [Standards Balloting and Commenting System \(SBS\)](#) until **8 p.m. Eastern, Tuesday, July 2, 2019**.

Commenting

Use the [SBS](#) to submit comments. If you experience issues navigating the SBS, contact [Wendy Muller](#). An unofficial Word version of the comment form is posted on the [project page](#).

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 8-17, 2019**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Comment: [View Comment Results](#)

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 AB 3 ST

Voting Start Date: 7/8/2019 12:01:00 AM

Voting End Date: 7/17/2019 8:00:00 PM

Ballot Type: ST

Ballot Activity: AB

Ballot Series: 3

Total # Votes: 310

Total Ballot Pool: 360

Quorum: 86.11

Quorum Established Date: 7/17/2019 3:54:41 PM

Weighted Segment Value: 87.39

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	94	1	67	0.87	10	0.13	0	8	9
Segment: 2	7	0.5	5	0.5	0	0	0	1	1
Segment: 3	84	1	59	0.894	7	0.106	0	5	13
Segment: 4	24	1	17	0.85	3	0.15	0	1	3
Segment: 5	85	1	57	0.838	11	0.162	0	4	13
Segment: 6	55	1	37	0.841	7	0.159	0	1	10
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	360	6.4	250	5.593	39	0.807	0	21	50

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted

5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		None	N/A
3	Piedmont EMC	Lawrence Hopkins Jr		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Network and Security Technologies	Nicholas Lauriat	Roger Fradenburgh	Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A

1	Colorado Springs Utilities	Mike Braunstein	None	N/A	
6	Seattle City Light	Charles Freeman	Affirmative	N/A	
6	WEC Energy Group, Inc.	David Hathaway	None	N/A	
3	Seattle City Light	Laurie Hammack	None	N/A	
6	APS - Arizona Public Service Co.	Chinedu Ochonogor	Negative	Comments Submitted	
1	Salt River Project	Steven Cobb	Affirmative	N/A	
5	AEP	Thomas Foltz	Affirmative	N/A	
2	PJM Interconnection, L.L.C.	Mark Holman	Affirmative	N/A	
6	Austin Energy	Andrew Gallo	None	N/A	
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Affirmative	N/A	
1	Southern Company - Southern Company Services, Inc.	Adrienne Collins	Negative	Comments Submitted	
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted	
6	Southern Company - Southern Company Generation	Ron Carlsen	Negative	Comments Submitted	
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro	Affirmative	N/A	
3	Silicon Valley Power - City of Santa Clara	Val Ridad	Affirmative	N/A	
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Long Island Power Authority	Robert Ganley	Affirmative	N/A	
5	Seattle City Light	Faz Kasraie	Affirmative	N/A	
4	WEC Energy Group, Inc.	Matthew Beilfuss	Affirmative	N/A	
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A	
3	Portland General Electric Co.	Dan Zollner	None	N/A	
5	Puget Sound Energy, Inc.	Eleanor Ewry	Affirmative	N/A	
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Affirmative	N/A	
5	Great River Energy	Preston Walsh	Affirmative	N/A	
1	U.S. Bureau of Reclamation	Richard Jackson	Negative	Comments Submitted	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A	
3	Cowlitz County PUD	Russell Noble	Affirmative	N/A	
6	Portland General Electric Co.	Daniel Mason	None	N/A	
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A	
6	TECO - Tampa Electric Co.	Benjamin Smith	None	N/A	
5	Nebraska Public Power District	Don Schmit	Affirmative	N/A	
3	TECO - Tampa Electric Co.	Ronald Donahey	None	N/A	
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta	Affirmative	N/A	
5	Acciona Energy North America	George Brown	None	N/A	
5	MEAG Power	Steven Grego	Abstain	N/A	
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A	

1	Eversource Energy	Quintin Lee	Affirmative	N/A	
5	Herb Schrayshuen	Herb Schrayshuen	Affirmative	N/A	
5	Talen Generation, LLC	Donald Lock	None	N/A	
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco	Affirmative	N/A	
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Davina Julienne	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A	
5	APS - Arizona Public Service Co.	Kelsi Rigby	Negative	Comments Submitted	
3	Modesto Irrigation District	Roderick Cook	None	N/A	
6	Modesto Irrigation District	James McFall	None	N/A	
6	PPL - Louisville Gas and Electric Co.	Linn Oelker	Affirmative	N/A	
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A	
1	Corn Belt Power Cooperative	larry brusseau	Affirmative	N/A	
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	N/A	
1	Exelon	Daniel Gacek	Affirmative	N/A	
3	Exelon	Kinte Whitehead	Affirmative	N/A	
5	Exelon	Cynthia Lee	Affirmative	N/A	
6	Exelon	Becky Webb	Affirmative	N/A	
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A	
1	Seattle City Light	Pawel Krupa	Affirmative	N/A	
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A	
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted	
4	Seattle City Light	Hao Li	Affirmative	N/A	
5	Duke Energy	Dale Goodwine	None	N/A	
6	Duke Energy	Greg Cecil	Affirmative	N/A	
3	Duke Energy	Lee Schuster	Affirmative	N/A	
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Affirmative	N/A	
4	Seminole Electric Cooperative, Inc.	Charles Wubbena	Affirmative	N/A	
1	OTP - Otter Tail Power Company	Charles Wicklund	Affirmative	N/A	
5	OTP - Otter Tail Power Company	Brett Jacobs	Affirmative	N/A	
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Affirmative	N/A	
3	OTP - Otter Tail Power Company	Wendi Olson	None	N/A	
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham	Affirmative	N/A	
3	Muscatine Power and Water	Seth Shoemaker	Affirmative	N/A	
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A	
6	Muscatine Power and Water	Ryan Streck	Affirmative	N/A	
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A	
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A	
6	Edison International - Southern California Edison Company	Kenya Streeter	Affirmative	N/A	

1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	James Woodall		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
5	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Troy Hlavaty	None	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A

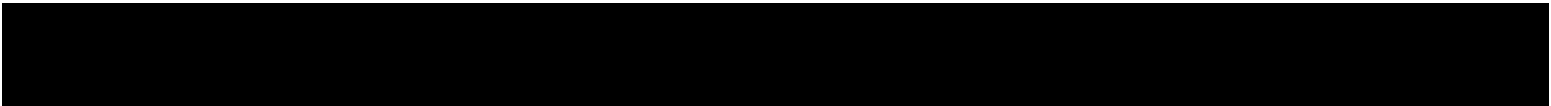
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	JEA	John Babik		None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A

1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	LaGen	Wayne Messina		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Rick Meadows		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		None	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	Intermountain REA	Pam Feuerstein		Affirmative	N/A

5	Oglethorpe Power Corporation	Donna Johnson	Negative	Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Donald Lynd	Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Negative	Comments Submitted
1	Lower Colorado River Authority	Trey Melcher	Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence	None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Affirmative	N/A
1	Santee Cooper	Chris Wagner	Negative	Comments Submitted
6	Santee Cooper	Michael Brown	Negative	Comments Submitted
3	Santee Cooper	James Poston	Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell	Affirmative	N/A
3	Salt River Project	Zack Heim	Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
4	National Rural Electric Cooperative Association	Barry Lawson	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
1	Peak Reliability	Michael Granath	Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative	N/A

1	LS Power Transmission, LLC	Darin Ferguson	Abstain	N/A
5	SunPower	Bradley Collard	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon	None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson	Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski	Negative	Comments Submitted
1	Memphis Light, Gas and Water Division	Allan Long	None	N/A
3	Eversource Energy	Sharon Flannery	Affirmative	N/A
1	JEA	Joe McClung	None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike O'Neil	Affirmative	N/A
6	New York Power Authority	Thomas Savin	Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
5	Avista - Avista Corporation	Glen Farmer	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Negative	Comments Submitted
3	Imperial Irrigation District	Denise Sanchez	Affirmative	N/A
5	Entergy	Jamie Prater	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
3	Lakeland Electric	Patricia Boody	Affirmative	N/A
5	AES - AES Corporation	Leo Bernier	Affirmative	N/A
1	City of College Station	Stacy Lee	Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson	Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Affirmative	N/A
1	Great River Energy	Gordon Pietsch	None	N/A
6	Northern California Power Agency	Dennis Sismaet	Negative	Comments Submitted
5	San Miguel Electric Cooperative, Inc.	Lana Smith	Affirmative	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith	Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel	Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea	Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski	Abstain	N/A
3	Great River Energy	Brian Glover	Affirmative	N/A

1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	None	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
1	Prairie Power, Inc.	Dick Chapman		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	Comments Submitted



[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 Non-binding Poll AB 3 NB

Voting Start Date: 7/8/2019 12:01:00 AM

Voting End Date: 7/17/2019 8:00:00 PM

Ballot Type: NB

Ballot Activity: AB

Ballot Series: 3

Total # Votes: 281

Total Ballot Pool: 333

Quorum: 84.38

Quorum Established Date: 7/17/2019 3:58:19 PM

Weighted Segment Value: 86.16

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	50	0.877	7	0.123	18	10
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	80	1	47	0.887	6	0.113	13	14
Segment: 4	20	1	11	0.846	2	0.154	4	3
Segment: 5	79	1	46	0.821	10	0.179	9	14
Segment: 6	51	1	29	0.829	6	0.171	7	9
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 1	1	0.1	1	0.1	0	0	0	0

9

Segment:	7	0.4	4	0.4	0	0	3	0
10								
Totals:	333	6	193	5.26	31	0.74	57	52

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Abstain	N/A
6	Salt River Project	Bobby Olsen		None	N/A

1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	City of Vero Beach	Ginny Beigel		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Network and Security Technologies	Nicholas Lauriat	Roger Fradenburgh	Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Affirmative	N/A

5	AEP	Thomas Foltz		Abstain	N/A
6	Austin Energy	Andrew Gallo		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Adrienne Collins		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	MEAG Power	Steven Grego		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Davina Julienne	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments

3	Modesto Irrigation District	Roderick Cook	None	N/A	
6	PPL - Louisville Gas and Electric Co.	Linn Oelker	None	N/A	
1	Corn Belt Power Cooperative	larry brusseau	Affirmative	N/A	
1	Exelon	Daniel Gacek	Affirmative	N/A	
3	Exelon	Kinte Whitehead	Affirmative	N/A	
5	Exelon	Cynthia Lee	Affirmative	N/A	
6	Exelon	Becky Webb	Affirmative	N/A	
1	Manitoba Hydro	Bruce Reimer	None	N/A	
1	Seattle City Light	Pawel Krupa	Affirmative	N/A	
6	Manitoba Hydro	Blair Mukanik	None	N/A	
4	Modesto Irrigation District	Spencer Tacke	None	N/A	
4	Seattle City Light	Hao Li	Affirmative	N/A	
5	Duke Energy	Dale Goodwine	None	N/A	
6	Duke Energy	Greg Cecil	Affirmative	N/A	
3	Duke Energy	Lee Schuster	Affirmative	N/A	
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Abstain	N/A	
4	Seminole Electric Cooperative, Inc.	Charles Wubbena	Abstain	N/A	
1	OTP - Otter Tail Power Company	Charles Wicklund	Abstain	N/A	
5	OTP - Otter Tail Power Company	Brett Jacobs	None	N/A	
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Affirmative	N/A	
3	OTP - Otter Tail Power Company	Wendi Olson	None	N/A	
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham	Affirmative	N/A	
3	Muscatine Power and Water	Seth Shoemaker	Affirmative	N/A	
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A	
6	Muscatine Power and Water	Ryan Streck	Affirmative	N/A	
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A	
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A	
6	Edison International - Southern California Edison Company	Kenya Streeter	Affirmative	N/A	
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Affirmative	N/A	
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour	Affirmative	N/A	
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Affirmative	N/A	
6	Ameren - Ameren Services	Robert Quinlivan	Affirmative	N/A	
1	Associated Electric Cooperative, Inc.	Ryan Ziegler	Affirmative	N/A	

1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	James Woodall		Abstain	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
5	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Troy Hlavaty	None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
	Great Plains Energy - Kansas City Power and				

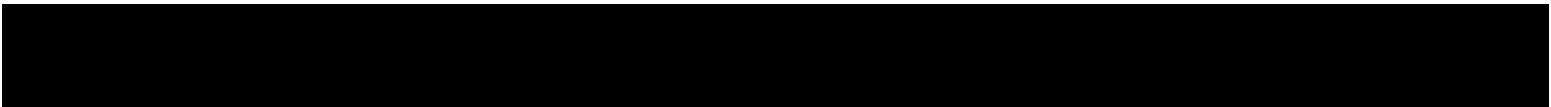
1	Light Co.	James McBee	Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo	Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch	None	N/A
1	Western Area Power Administration	sean erickson	Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi	Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	None	N/A
1	Lakeland Electric	Larry Watt	Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell	None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Abstain	N/A
8	David Kiguel	David Kiguel	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
3	National Grid USA	Brian Shanahan	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott	Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel	None	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	Affirmative	N/A

5	JEA	John Babik		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
	Great Plains Energy - Kansas City Power and				

3	Light Co.	John Carlson		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
6	Lakeland Electric	Paul Shippo		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Lower Colorado River Authority	Trey Melcher		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	Peak Reliability	Michael Granath		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A

6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson	Abstain	N/A
5	SunPower	Bradley Collard	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver	None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson	Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski	Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long	None	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco	Affirmative	N/A
3	Eversource Energy	Sharon Flannery	Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil	Affirmative	N/A
6	New York Power Authority	Thomas Savin	Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
5	Avista - Avista Corporation	Glen Farmer	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Negative	Comments Submitted
3	Imperial Irrigation District	Denise Sanchez	Negative	Comments Submitted
5	Entergy	Jamie Prater	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
3	Lakeland Electric	Patricia Boody	Affirmative	N/A
5	AES - AES Corporation	Leo Bernier	Affirmative	N/A
1	City of College Station	Stacy Lee	Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson	Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Affirmative	N/A
1	Great River Energy	Gordon Pietsch	None	N/A
6	Northern California Power Agency	Dennis Sismaet	Negative	Comments Submitted
5	San Miguel Electric Cooperative, Inc.	Lana Smith	Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Abstain	N/A
5	NaturEner USA, LLC	Eric Smith	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel	Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea	Abstain	N/A

10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	None	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
1	Prairie Power, Inc.	Dick Chapman		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	Comments Submitted



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	June 3 – July 18, 2019
45-day formal comment period with additional ballot	November 1 – December 16, 2019

Anticipated Actions	Date
10-day final ballot	January 24 – February 3, 2020
NERC Board	February 2020

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. The identification and categorization of BES Cyber Systems supports appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

- 4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates: See Implementation Plan for CIP-002-6.**

6. **Background:**

This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the characteristics in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than “Real-time,” BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples include, to the extent they are within the ESP: file servers, FTP servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber System according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber System according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

- 2.5** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9** Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11** Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry's overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document¹ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

One of the issues identified was ongoing confusion as to the scope of Criterion 2.12. The V5TAG recommended clarification of the criterion, specifically around the phrase "used to perform the functional obligations of the Transmission Operator," and to introduce more precise thresholds for when a Control Center's BES Cyber Systems performing such functions should be in the Medium or Low category in Attachment 1.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to Criterion 2.12 to clarify the applicability of requirements on a Transmission Owner Control Center that performs the functional obligations of a Transmission Operator.

The proposed criterion establishes a weighted value for BES Transmission Lines monitored and controlled by the Control Center based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center's associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center's associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

- 2.12.** Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the

¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services.

- These named services include: Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities,” there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as, “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the

group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term

“must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or

substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in Attachment 1 of NERC's "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)" document, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV

or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding

requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

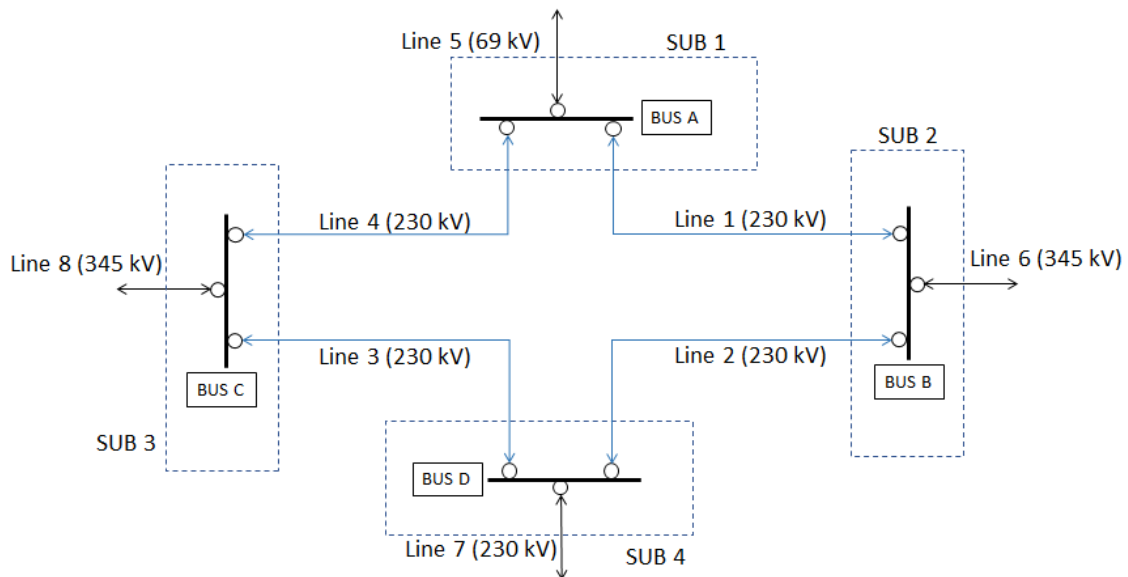
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and

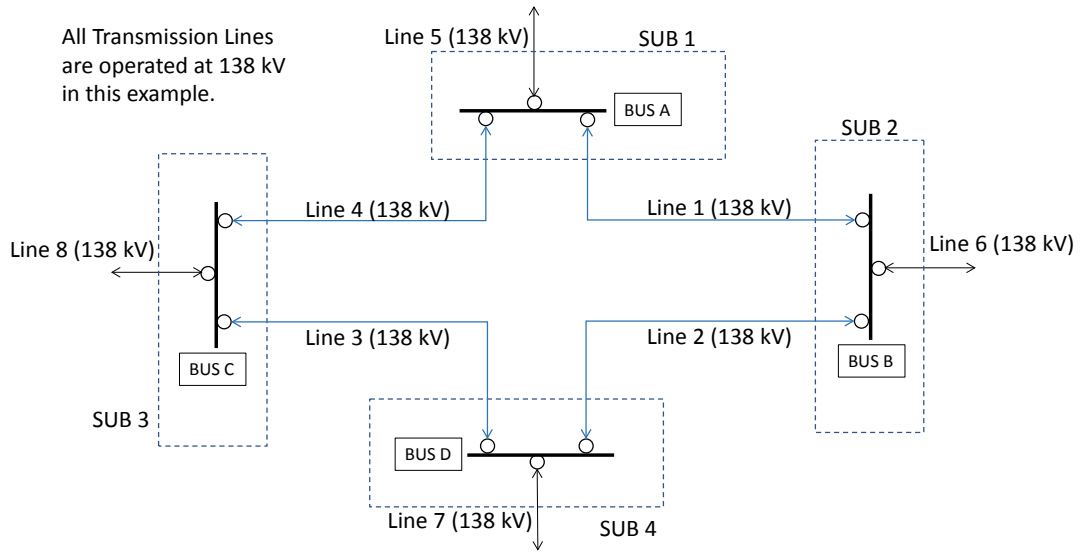
equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

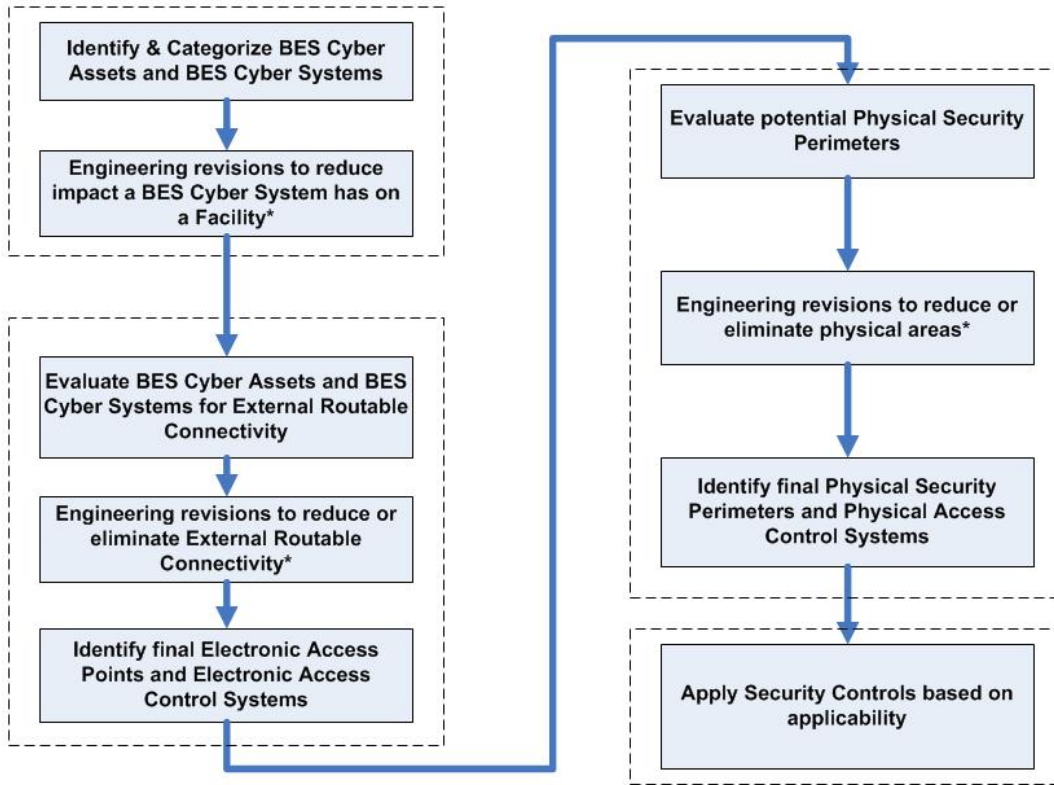
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the ~~third~~fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	June 3 – July 18, 2019
<u>45-day formal comment period with additional ballot</u>	<u>November 1 – December 16, 2019</u>

Anticipated Actions	Date
10-day final ballot	July <u>January</u> 24 – August 2 <u>February 3,</u> 20 <u>2019</u>
NERC Board	August 15, <u>2019</u> <u>February 2020</u>

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-~~5.1a6~~
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. The identification and categorization of BES Cyber Systems supports appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** -For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” -For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~**4.1.6.4.1.5. Reliability Coordinator**~~

~~**4.1.7.4.1.6. Transmission Operator**~~

~~**4.1.8.4.1.7. Transmission Owner**~~

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

- 4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
- 4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
- 4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-002-6.

~~6. 24 Months Minimum — CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~7. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

8.6. Background:

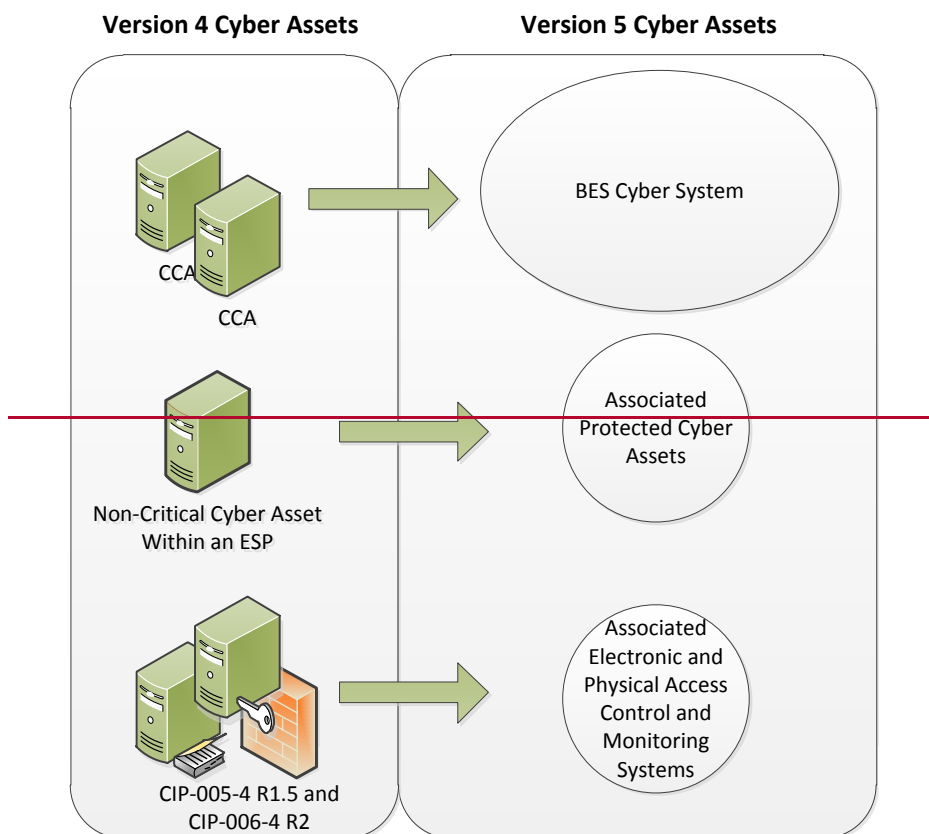
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.~~



~~In~~ transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply. Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-

developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the characteristics in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these ~~Version 5~~-CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement **R1** only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria,

~~Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11~~Section 1 or Section 2, and listed in Section 3 default to ~~be~~ low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the ~~Version 5~~ CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)** Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples ~~may~~ include, to the extent they are within the ESP: file servers, ~~ftp-FTP~~ servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** ~~The Each~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

~~None.~~

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

F. Associated Documents

None.

Version History

~~CIP-002-5.1a-~~

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.

Version	Date	Action	Change Tracking
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating ~~(H)~~

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4** Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9** Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- ~~**2.12** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance on possible methods to achieve compliance with the CIP V5 standards and to support industry’s overall implementation activities. In the course of its activities, the V5TAG identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document¹ to formally recommend that the SDT address these issues during the standards development process and consider making modifications to the standard language.

One of the issues identified was ~~Due to the ongoing confusion as to the scope of Criterion 2.12. of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12,~~†The V5TAG recommended clarification of the criterion, specifically around the phrase “used to perform the functional obligations of the Transmission Operator,-” and to introduce more precise thresholds for when a Control Center’s BES Cyber Systems performing such functions should be in the Medium or Low category in Attachment 1.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to ~~CIP-002-5.1a, Attachment 1,~~ Criterion 2.12 to clarify the applicability of requirements on a Transmission Owner Control Center that performs the functional obligations of a Transmission Operator.

The proposed criterion establishes a weighted value for BES Transmission Lines monitored and controlled by the Control Center based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value must exceed 6000 to meet the minimum threshold established in Criterion 2.12. This is calculated by summing the "weight value per line" shown in the associated table for each

¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be categorized as low impact pursuant to Criterion 3.1.

2.12. Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating ~~(L)~~

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Special Protection SystemsRemedial Action Schemes that support the reliable operation of the Bulk Electric System.

- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-~~5.1a6~~ and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-~~5.1a6~~. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-~~5.1a6~~

CIP-002-~~5.1a6~~ requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. -The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-~~5.1a-6~~. The concept includes a number of named BES reliability operating services.

- These named services include: Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. -The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering

action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)

- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the

reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities,” there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as, “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along

with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-~~5.1a6~~, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating ~~(H)~~

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, ~~BA~~s, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of

BA footprints shows that the majority of ~~Bas~~BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating ~~(M)~~

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is “to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.” In particular, it requires that “as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency.” The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a “long term” reliability planning, i.e. that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is

necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.

- Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in [Attachment 1 of NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index" document, Attachment 1](#), the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems ~~for those Special Protection Systems (SPS)~~, Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a, that monitor and control BES Transmission Operator Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient

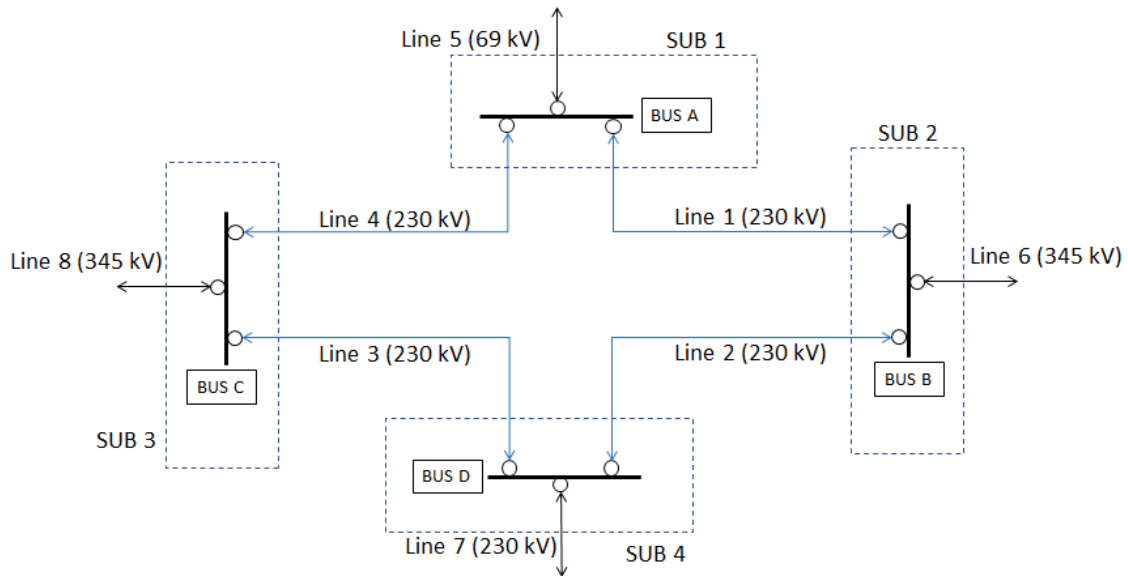
differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

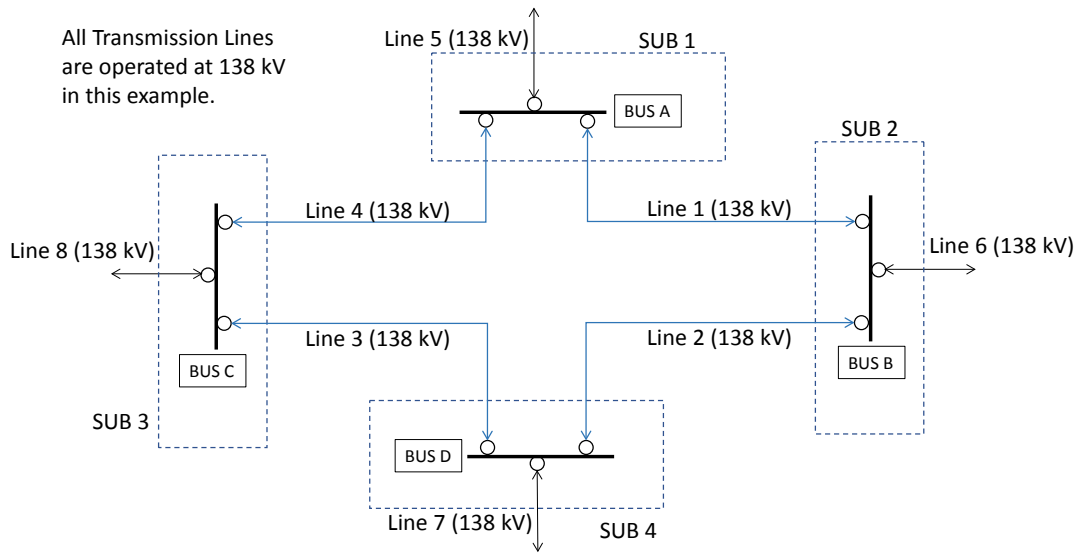
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>Line 5</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>None</u>	<u>0</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 7</u>	<u>3500</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>Line 6, Line 8</u>	<u>2600</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as high impact, a low impact BES Cyber System(s) pursuant to Criterion 3.1.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>None</u>	<u>N/A</u>

<u>100 kV to 199 kV</u>	<u>250</u>	<u>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</u>	<u>2000</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>None</u>	<u>0</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>None</u>	<u>0</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not

relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

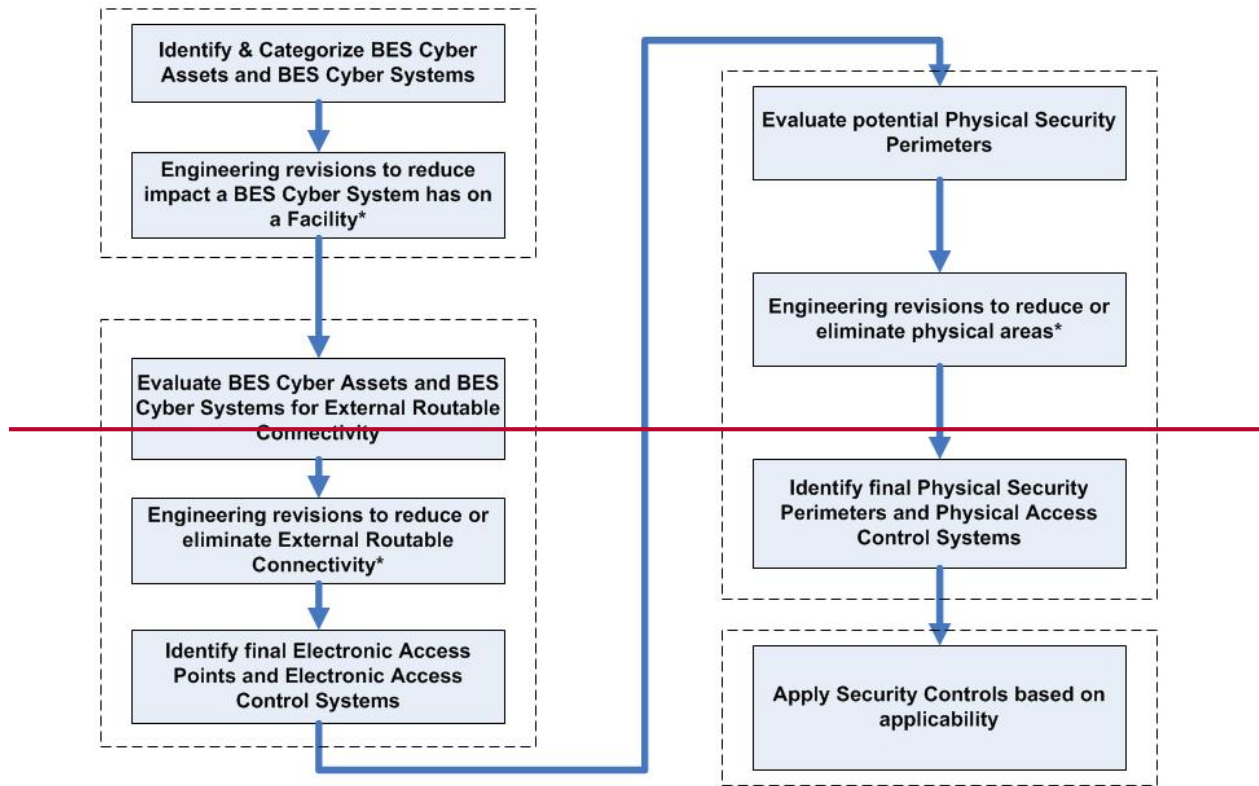
Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example

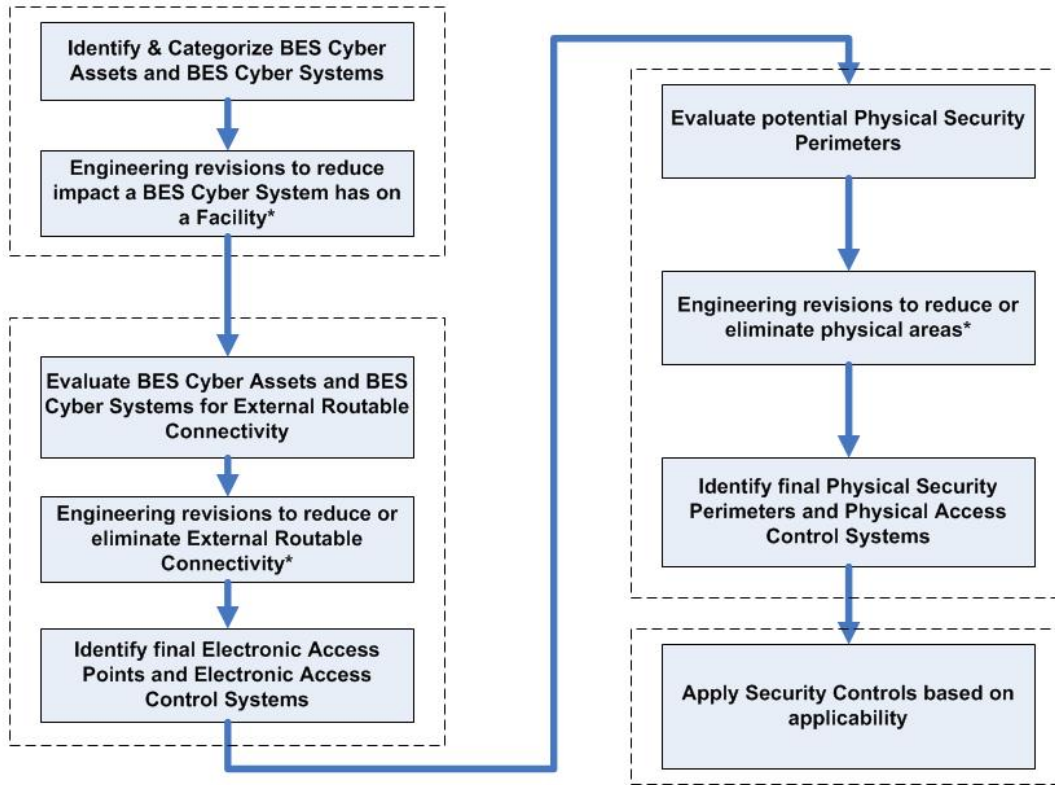
of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale⁺

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization

Prerequisite Standard(s) or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

This Implementation Plan includes a phased-in implementation dates for Criterion 2.12 of CIP-002-6, Attachment 1. The phased-in implementation dates allow Responsible Entities¹ a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion of it),

¹ As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter immediately after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 of Attachment 1 to CIP-002-6 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For *planned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the responsible entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *unplanned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium-Impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible entity identifies its first high impact or medium impact BES Cyber System (i.e., the responsible entity previously had no BES	24 months

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes)	

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards

CIP-002-6

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments on **CIP-002-6 - Cyber Security – BES Cyber System Categorization**. Comments must be submitted by **8 p.m. Eastern, Monday, December 16, 2019**.

Additional information is available on the [project page](#). If you have questions, contact Standard Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

Background Information

Project 2016-02 was formed to (1) address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 822 and (2) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document).

The V5TAG, which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP Version 5 standards and to support industry's implementation activities. During the V5TAG's activities, it identified certain issues with the CIP Reliability Standards that would be better addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the [CIP Version 5 Transition Advisory Group Issues for Consideration](#) document to formally recommend that the SDT address these issues and consider modifications to the standard language during the standards development process. Among other issues of the V5TAG recommended clarification of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12. The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes an average MVA line loading based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12. The aggregate weighted value is calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the BES Cyber System(s) exceeds the 6000 aggregate weighted value, it should be identified as a medium impact BES Cyber System. If the BES Cyber System does not exceed the 6000 aggregate weighted value, it should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

The drafting team received comments from the July 2019 45-day comment and ballot period regarding the Planned and Unplanned changes section within CIP-002-6. Upon consideration of these comments and the issues raised, the team determined that the matter of the CIP-002 identification and

categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a SAR will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the TOCC modifications and other minor updates (i.e., removal of the retired term SPS, etc.).

Questions

1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

- Yes
 No

Comments:

3. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

- Yes
 No

Comments:

4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-002-6**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

Justification for VRFs and VSLs

- Requirement R1: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.
- Requirement R2: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through December 16, 2019

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, December 16, 2019**.

Responses regarding the Planned and Unplanned changes section within CIP-002-6 were received from the July 2019 45-day comment and ballot period. Upon consideration of these comments and the issues raised, the drafting team determined that the matter of the CIP-002 identification and categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore, the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the TOCC modifications and other minor updates (i.e., removal of the retired term SPS, etc.).

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. Contact [Wendy Muller](#) regarding issues using the SBS. An unofficial Word version of the comment form is posted on the [project page](#).

- *Contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **December 6-16, 2019**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2016-02 Modifications to CIP Standards | CIP-002-6 (Draft 4)
Comment Period Start Date: 11/1/2019
Comment Period End Date: 12/16/2019
Associated Ballots: 2016-02 Modifications to CIP Standards CIP-002-6 AB 4 ST

There were 52 sets of responses, including comments from approximately 119 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

- 1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.**
- 2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.**
- 3. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.**
- 4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Eric Jensen	Arizona Electric Power Cooperative	1	WECC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					Joseph Smith	Prairie Power , Inc.	1,3	SERC
					Carl Behnke	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF

					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC

Michele Tondalo	UI	1	NPCC
Helen Lainis	IESO	2	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
David Kiguel	Independent	NA - Not Applicable	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Mike Forte	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC

					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power	1	SERC

	Electric Cooperative		
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
Tony Gott	KAMO Electric Cooperative	3	SERC
Micah Breedlove	KAMO Electric Cooperative	1	SERC
Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer No

Document Name

Comment

The changes add clarification, however, the extremely long sentences are awkward and will cause confusion in application of the approved standards.

Likes 0

Dislikes 0

Response

James Baldwin - Eugene Water and Electric Board - 1,3 - WECC

Answer No

Document Name

Comment

EWEB believes that criterion 2.12 places undue hardship on utilities that have a robust system. EWEB's system is designed to provide reliable load; however, due to the new, ambiguous aggregate rating, EWEB would be classified as a Medium Impact entity. The new criterion places undue hardships on smaller utilities that do not have the resources available to efficiently comply with the CIP Medium Impact Standards.

Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.

An alternative to the aggregate weight of number of lines a Transmission Owner has could be the total distance of lines owned in kV categories.

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer No

Document Name

Comment

The "aggregate weighted value" concept of Criterion 2.12 is acceptable. However, Criterion 2.12 uses the phrase, "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" while Criterion 1.3 uses the different phrase, "used to perform the functional obligations of the Transmission Operator." The two criteria should use the same language in order to prevent gaps in applicability between the two criteria.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

No

Document Name

Comment

As previously submitted, Texas RE is concerned the proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators (TOP) or just TOP that currently have medium impact BES Cyber Systems because of 2.12; to become low impact.

- TO's performing functional obligations of TOP's and TOP Control Centers operating BES Transmission Lines less than 200 kV will go from having medium impact BES Cyber Systems to low impact BES Cyber Systems if the BES Transmission Lines do not have an "aggregate weighted value" exceeding 6000 according to the table in 2.12.
- Texas RE is concerned this will have a negative impact on reliability since less BES assets and BES Cyber Systems would be protected under the proposed revisions and become low impact.
 - There are no baselining, vulnerability assessment, ports and services, security patching, malicious code prevention, etc... Requirements for assets that contain low impact BES Cyber Systems.

Likes 0

Dislikes 0

Response

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Answer

No

Document Name

Comment

Similar to Criteria 2.5, Criteria 2.12 should only count lines connected to substations by three or more BES transmission lines. As written, the criteria overestimates the impact of small distribution substations that have a transmission line looped through the substation rather than just tapping the transmission line. As an example, consider a 115 kV transmission line connecting two major substations. Connected to this transmission line are five small unit substations serving load. Under the SDT proposal, if local distribution substations are tapped off of the line, the total weighted value would be

250. If the line is looped through each distribution substation, the line would instead have a weighted value of 1500. The looped through line typically has much better reliability, so weighting it six times worse seems inconsistent with improved reliability.

A previous Considerations of Comments stated that the value of 6000 was based on NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index. https://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf" However, the SRI does not actually address lines less than 200 kV. The SRI was written in 2011, based on TADS data available at the time. TADS did not include complete reliability information on lines less than 200 kV until 2014. Lines below 200 kV typically configured differently than lines above 200 kV, with lower voltage lines often directly serving load. The SRI equation includes terms for both lost transmission lines and for lost load. Since lower voltage lines are much more likely than higher voltage lines to directly serve load, extrapolating data from higher voltages will incorrectly categorize risk.

Likes 0

Dislikes 0

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer

No

Document Name

Comment

In Section 2.12 , the phrase "...BES Transmission Lines with a..." should be revised to "...BES Transmission Lines and any other transmission lines operated at 60 kV and above with a...".

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

I don't believe the standard was unclear before. I believe NERC, FERC, and Regional Entities were over reaching and should have been more reasonable and less overreaching. For instance:

New IRC 2.12 does not need to say **BES** Transmission lines or **Monitored and Controlled**. CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says "All BES Facilities" it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line's capability to be included in an IRC 2.11 or 2.12 evaluation.

I believe this is all being done because FERC incorrectly produced section 3 page 10 of <https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf>. FERC's report says "For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation

Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all “non-BES generation” in their calculations. Foot note 9.” Footnote 9 on Page 10 says “CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms “BES Generation,” and “Non-BES Generation.” Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don’t need to! You don’t have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit!

In my view FERC’s footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only.

Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?"

Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets?

It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s).

It ironic that NERC recently had another Project recently up for Ballot “Moving Technical Rational Sections” out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.

Likes	0
-------	---

Dislikes	0
----------	---

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
---------------	-----

Document Name	
----------------------	--

Comment

None

Likes	0
-------	---

Dislikes	0
----------	---

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	
Comment	
We agree with the drafting team, but we believe that Criterion 2.12 should be expanded to include any Control Center that operates a Medium Impact substation should be considered Medium Impact BES Cyber System (BCS).	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the proposed modification and appreciates the establishment of a bright line criteria between Low and Medium Impact Control Centers. The proposed change provides Registered Entities clarity which will help ensure that they have properly and consistently classified their BES facilities and assets.	
Likes 0	
Dislikes 0	
Response	
Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Duke Energy generally agrees with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable**Answer** Yes**Document Name****Comment**

EEI agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.

Likes 0

Dislikes 0

Response**Clay Walker - Cleco Corporation - 1,3,5,6 - SERC****Answer** Yes**Document Name****Comment**

See EEI comments.

Likes 0

Dislikes 0

Response**Terry Volkmann - Glencoe Light and Power Commission - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Chinedu Ochonogor - APS - Arizona Public Service Co. - 6****Answer** Yes**Document Name**

Comment

Likes 0

Dislikes 0

Response**Kjersti Drott - Tri-State G and T Association, Inc. - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**LaTroy Brumfield - American Transmission Company, LLC - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response**Laura Nelson - IDACORP - Idaho Power Company - 1****Answer**

Yes

Document Name**Comment**

Likes 0

Dislikes 0

Response

Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3**Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Kent Feliks - AEP - 3****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Bruce Reimer - Manitoba Hydro - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response**Stacy Lee - City of College Station - 1****Answer** Yes**Document Name****Comment**

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
Answer	Yes
Document Name	
Comment	

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Marty Hostler - Northern California Power Agency - 5

Answer No

Document Name

Comment

Planned an unplanned language was never in the SAR and never should have been debated. And never should be. NERC/FERC was trying to take a GOP emphirical operations based data IRC 2.11 and change it to an unproven theoritically based criteria (Planned Changes). Totally unreasonable over regulation attempts.

Please I praise the STD for reverting back to the old implementation plan. But it was changed a little bit or word order changes. Why couldn't language be really reverted back to current state" ?

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer No

Document Name

Comment

San Miguel agrees with comments submitted by NRECA.

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer No

Document Name

Comment

AECI supports comments filed by NRECA as such:

NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the “Planned Changes” section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the “Initial Performance of Periodic Requirements” section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the “Initial Performance of Periodic Requirements” section be revised to state:

“After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement.”

Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of “Planned” and “Unplanned” changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.

Likes 0

Dislikes 0

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio

Answer

No

Document Name

Comment

NCEMC supports NRECA's Comments

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer

No

Document Name

Comment

NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the “Planned Changes” section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the “Initial Performance of Periodic Requirements” section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011.

Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the “Initial Performance of Periodic Requirements” section be revised to state:

“After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement.”

Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of “Planned” and “Unplanned” changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.

Likes 0

Dislikes 0

Response

Andrea Barclay - Georgia System Operations Corporation - 4

Answer No

Document Name

Comment

GSOC has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the planned changes section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the initial performance of certain periodic requirements appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, GSOC recommends that the initial performance of certain periodic requirements be revised to state:

After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made

into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

“Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity **and** subsequently identified through the annual assessment under CIP-002-6, Requirement R2.”

The “and” in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System’s compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.

Likes 0

Dislikes 0

Response

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer Yes

Document Name

Comment

See EEI comments.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer Yes

Document Name

Comment

: We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The proposed language for planned and unplanned changes in the current implementation planned removed the rigor to ensure that BES Cyber Systems that can impact the Bulk Electric System are compliant to the CIP Standards within the timeframes specified for planned or unplanned changes. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

“Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.”

The “and” in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System’s compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer Yes

Document Name

Comment

EEl supports the proposed modification.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson

Answer Yes

Document Name

Comment

PG&E appreciates the SDT reverting the Planned and Unplanned Changes back to the original CIP-005-5 conditions until an appropriate SAR can be proposed to address the conditions raised in the July 2019 CIP-002-6 comment and ballot.

Likes 0

Dislikes 0

Response

Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC

Answer Yes

Document Name

Comment

Duke Energy generally agrees with the proposed modifications. However, the speed in which solar sites are being built does not allow sufficient time to build physical security controls without delaying solar connection to the grid. Duke would like to see an implementation plan for newly build generation which allows the registered entity a specified amount of time (6 months) to complete compliance tasks and documentation.

Duke Energy would like the unplanned change definition to include purchases of new generation as well. The registered entity knows the purchase is taking place, but the plant will need to be included in the Duke program after the purchase date.

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

Yes

Document Name

Comment

Southern agrees with reverting this wording back to the "current state". Moving this proposed change to a separate SAR will give the SDT and the industry much needed time to fully explore additional options and appropriately weigh any compliance risk associated with the change.

Likes 0

Dislikes 0

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer

Yes

Document Name

Comment

We agree with the change, however it should be clear that the implementation schedule is applicable to any of the unplanned change type listed on the table of CIP-002-6 on page 3 and is enforceable going forward, not just during transition from CIP-002-5.1a to CIP-002-6.

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1,

3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.

Likes	0
-------	---

Dislikes	0
----------	---

Response

--

Daniel Gacek - Exelon - 1

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

Exelon supports the proposed modification.

Likes	0
-------	---

Dislikes	0
----------	---

Response

--

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
--------	-----

Document Name	
---------------	--

Comment

The existing language from the CIP-002-5.1a Implementation Plan moved into the CIP-002-6 Implementation Plan provides shorter implementation periods than the Planned and Unplanned Changes section stricken from CIP-002-6 Draft 3. Specifically, Draft 3 provided 24 calendar months for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, whereas the new Implementation Plan only provides 12 months. The wording of Question 2 does not make that clear. Request industry be advised of this impact.

Likes	0
-------	---

Dislikes	0
----------	---

Response

David Jendras - Ameren - Ameren Services - 3

Answer Yes

Document Name

Comment

Ameren supports EEI comments for this question; therefore we support the proposed modification.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer Yes

Document Name

Comment

Reclamation supports the concept of different compliance implementation dates for planned versus unplanned changes. Reclamation recommends the compliance implementation date be calculated from the date the modified BES Cyber System is capable of impacting the BES. This will allow time for testing and returning existing equipment to service without the need to document compliance of equipment that is not capable of causing an adverse reliability impact.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Yes

Document Name

Comment

None

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Carl Pineault - Hydro-Quebec Production - 1,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Terry Volkmann - Glencoe Light and Power Commission - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE recommends including additional examples under Planned Changes to include Generation Facilities and Control Centers. Responsible Entities have struggled with the interpretation of what “*upon the commissioning*” means.

Texas RE noticed the following:

- “Responsible Entities” is capitalized throughout the Standard but not in the Implementation Plan. Texas RE recommends the term be capitalized and the language explaining “Responsible Entities” added for clarity and consistency.
- In the table for “unplanned changes” the term “Medium-Impact” is capitalized/hyphenated and should not be for consistency.

Likes 0

Dislikes 0

Response

3. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

James Baldwin - Eugene Water and Electric Board - 1,3 - WECC

Answer No

Document Name

Comment

Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.

Likes 0

Dislikes 0

Response

Daniel Gacek - Exelon - 1

Answer Yes

Document Name

Comment

Exelon supports the proposed modification in terms of the flexibility it provides to meet reliability objectives in a cost effective manner..

Likes 0

Dislikes 0

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.

Likes 0

Dislikes 0

Response

Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC

Answer

Yes

Document Name

Comment

Duke Energy generally does not agree that the proposed modifications in CIP-002-6 are cost effective. Duke Energy generally does not agree that they pose a financial burden.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson

Answer

Yes

Document Name

Comment

As provided in PG&E comments as part of the July 2019 comment and ballot period, PG&E believes the 24 month time-frame is sufficient to apply the necessary Requirement changes when the impact rating goes from low to medium, or medium to high. While PG&E has not experienced changes in impact rating that would elevate a BCS impact rating, our experience on the application of the Requirements for medium and high BCS does not suggest a longer time-frame would be necessary.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Yes

Document Name

Comment

none

Likes 0

Dislikes 0

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Terry Volkmann - Glencoe Light and Power Commission - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Chinedu Ochonogor - APS - Arizona Public Service Co. - 6

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer

Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Kent Feliks - AEP - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Bruce Reimer - Manitoba Hydro - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Stacy Lee - City of College Station - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tim Womack - Puget Sound Energy, Inc. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer

Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Pam Feuerstein - Intermountain REA - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

None

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

Ameren supports EEI comments for this question; therefore we will not submit comments on cost effectiveness of the proposed changes.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE does not have comments on this question.

Likes 0

Dislikes 0

Response

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer

Document Name

Comment

See EEI comments.

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 5

Answer

Document Name

Comment

No NERC needs to include real cost estimate. Take a look at a recent WECC Controls webinar and include those cost too in all standards.

Likes 0

Dislikes 0

Response

4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.

Marty Hostler - Northern California Power Agency - 5

Answer

Document Name

Comment

New IRC 2.12 does not need to say **BES** Transmission lines or **Monitored and Controlled**. CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says "All BES Facilities" it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line's capability to be included in an IRC 2.11 or 2.12 evaluation.

I believe this is all being done because FERC incorrectly produced section 3 page 10 of <https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf>. FERC's report says "For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all "non-BES generation" in their calculations. Footnote 9." Footnote 9 on Page 10 says "CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms "BES Generation," and "Non-BES Generation." Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don't need to! You don't have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit!

In my view FERC's footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only.

Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?"

Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets?

It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s).

It ironic that NERC recently had another Project recently up for Ballot "Moving Technical Rational Sections" out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.

Likes 0

Dislikes 0

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

Document Name

Comment

NV Energy believes additional guidance is necessary regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0

Dislikes 0

Response

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer

Document Name

Comment

EEI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6:

1. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)".
2. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model, therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.
3. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC's Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
4. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6.
5. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.

6. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0

Dislikes 0

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Document Name

Comment

We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0

Dislikes 0

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer

Document Name

Comment

We thank the SDT for allowing us to provide comments on these changes.

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer

Document Name

Comment

San Miguel appreciates the efforts of the SDT on this project.

Likes 0

Dislikes 0

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI appreciates the efforts of the SDT on these issues.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE noticed the following:

- In the section “BES Cyber Systems”, there appears to be incorrect grammar in first sentence discussing transition.
- Starting on page 10, the footer information contains the incorrect draft version and date.

Likes 0

Dislikes 0

Response

Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch

Answer

Document Name

Comment

MISO supports the additional clarity provided in the Supplemental Material (on page 29, under "Medium Impact Rating" and page 38 under "Low Impact Rating"); i.e. "No additional evaluation is necessary for BES Cyber Systems that have already been identified as high (or medium) impact."

Likes 0

Dislikes 0

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer**Document Name****Comment**

Comments: EEI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6:

1. Page 5 of the Redline, Section 6, Background, under subheading "BES Cyber Systems", the first word in the sentence (transitioning) needs to be capitalized.
2. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)".
3. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model, therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.
4. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC's Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
5. The footnote on all pages (i.e., page 10 moving forward) incorrectly still references Draft 3 of CIP-002-6.
6. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.
7. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0

Dislikes 0

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio

Answer	
Document Name	
Comment	
NCEMC appreciates the efforts of the SDT on these issues.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	
Document Name	
Comment	
PG&E provides no additional comments.	
Likes 0	
Dislikes 0	
Response	
Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Duke Energy has the following additional comments - The second paragraph in Criterion 2.1 on page 29 of 45 states "to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024" The MOD-024 Standard has been retired and should be removed as a reference.	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	

Document Name	
Comment	
NRECA appreciates the efforts of the SDT on these issues.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
While draft 3 provided additional time (24 calendar months) for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, Southern understands that removing the proposed change associated with “time frames to implement” while reverting to the previous language makes sense. We look forward to the opportunity to actively participate in addressing this as a part of a future proposed change which encompasses addressing planned and unplanned changes, as a whole.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
Provide clearer examples for each of the listed items in the implementation table for the unplanned section.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Quebec Production - 1,5	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
<p>Exelon supports the comments offered by EEI, as reflected here:</p> <ol style="list-style-type: none"> Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)". Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC's Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded 	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	

Answer	
Document Name	
Comment	
AEP has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.	
Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
The posted version has incorrect grammar in R1, Parts 1.1 and 1.2. Please change Part 1.1 from "Identify each of the high impact BES Cyber System" to "Identify each high impact BES Cyber System". Please change Part 1.2 from "Identify each of the medium impact BES Cyber System" to "Identify each medium impact BES Cyber System". Also please consider requiring explicit identification of associated systems (currently EACMS, PACS, PCA) for inclusion in the standard language (e.g. R1 P1.4) for high and medium impact BES Cyber Systems. Suggested wording: "Identify each EACMS, PACS, and PCA associated with a high impact BES Cyber System or a medium impact BES Cyber System." This addition would serve to remind Responsible Entities that such identifications are required, and will permit assessing a violation, if applicable, against only one Requirement.	
Likes 0	
Dislikes 0	

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

Ameren agrees with and supports EEI comments for this question.

Likes 0

Dislikes 0

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer

Document Name

Comment

Reclamation recommends the SDT add the definitions of Planned Changes and Unplanned Changes to the NERC Glossary of Terms.

Likes 0

Dislikes 0

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

None

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer

Document Name

Comment

ATC supports the commetns of EEI.

Likes 0

Dislikes 0

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer

Document Name

Comment

I find the standard difficult to read with the various references back and forth between the Standard and Attachment 1. Ideally, the references should be mimized. This may be an issue in enforcement, and could cause some confusion to some entities.

Likes 0

Dislikes 0

Response

Consideration of Comments

Project Name:	2016-02 Modifications to CIP Standards CIP-002-6 (Draft 4)
Comment Period Start Date:	11/1/2019
Comment Period End Date:	12/16/2019
Associated Ballots:	2016-02 Modifications to CIP Standards CIP-002-6 AB 4 ST

There were 52 sets of responses, including comments from approximately 119 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Vice President of Engineering and Standards [Howard Gugel](#) (via email) or at (404) 446-9693.

Questions

1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.
2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.
3. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.
4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Eric Jensen	Arizona Electric Power Cooperative	1	WECC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					Joseph Smith	Prairie Power , Inc.	1,3	SERC
					Carl Behnke	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC					
Joel Charlebois	AESI - Acumen Engineered	5	NPCC					

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Solutions International Inc.		
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer No

Document Name

Comment

The changes add clarification, however, the extremely long sentences are awkward and will cause confusion in application of the approved standards.

Likes 0

Dislikes 0

Response: Thank you for your comment. The SDT agrees that the sentences in Criterion 2.12 are long. However, in response to previous comment periods and issues raised, much was needed to clearly convey the intent of the criterion.

James Baldwin - Eugene Water and Electric Board - 1,3 – WECC

Answer No

Document Name

Comment

EWEB believes that criterion 2.12 places undue hardship on utilities that have a robust system. EWEB's system is designed to provide reliable load; however, due to the new, ambiguous aggregate rating, EWEB would be classified as a Medium Impact entity. The new criterion places undue hardships on smaller utilities that do not have the resources available to efficiently comply with the CIP Medium Impact Standards.

Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.

An alternative to the aggregate weight of number of lines a Transmission Owner has could be the total distance of lines owned in kV categories.

Likes 0

Dislikes 0

Response: Thank you for your comment. The current enforceable version of CIP-002 does not allow BES Cyber Systems associated with a Control Center that performs the functional obligation of the Transmission Operator (TOP) to be categorized as low impact. The revisions to Criterion 2.12 set a floor for medium impact BES Cyber Systems at Control Centers that perform the functional obligation of the TOP, which allows Control Centers of lower risk to categorize their BES Cyber Systems as low impact. During the development process, the SDT discussed using line miles to help determine categorization but received feedback that line miles do not necessarily identify the criticality of the BES Elements.

Anthony Jablonski - ReliabilityFirst – 10

Answer

No

Document Name

Comment

The “aggregate weighted value” concept of Criterion 2.12 is acceptable. However, Criterion 2.12 uses the phrase, “used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines” while Criterion 1.3 uses the different phrase, “used to perform the functional obligations of the Transmission Operator.” The two criteria should use the same language in order to prevent gaps in applicability between the two criteria.

Likes 0

Dislikes 0

Response: Thank you for your comment. The SDT developed the proposed language in Criterion 2.12 to emphasize the real-time aspects associated with the functional tasks performed at Control Centers, regardless of the entity’s functional registration. The SDT contends that the proposed language is suitable for medium impact BES Cyber Systems that do not meet the high impact categorization detailed in Criterion 1.3.

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer

No

Document Name

Comment

As previously submitted, Texas RE is concerned the proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators (TOP) or just TOP that currently have medium impact BES Cyber Systems because of 2.12; to become low impact.

- TO’s performing functional obligations of TOP’s and TOP Control Centers operating BES Transmission Lines less than 200 kV will go from having medium impact BES Cyber Systems to low impact BES Cyber Systems if the BES Transmission Lines do not have an "aggregate weighted value" exceeding 6000 according to the table in 2.12.
- Texas RE is concerned this will have a negative impact on reliability since less BES assets and BES Cyber Systems would be protected under the proposed revisions and become low impact.
 - There are no baselining, vulnerability assessment, ports and services, security patching, malicious code prevention, etc... Requirements for assets that contain low impact BES Cyber Systems.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. NERC has conducted a study where no additional identifiable risks were shown, and the Regional Entities were provided a chance to review the results.

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) – 3

Answer	No
Document Name	

Comment

Similar to Criteria 2.5, Criteria 2.12 should only count lines connected to substations by three or more BES transmission lines. As written, the criteria overestimates the impact of small distribution substations that have a transmission line looped through the substation rather than just tapping the transmission line. As an example, consider a 115 kV transmission line connecting two major substations. Connected to this transmission line are five small unit substations serving load. Under the SDT proposal, if local distribution substations are tapped off of the line, the total weighted value would be 250. If the line is looped through each distribution substation, the line would instead have a weighted value of 1500. The looped through line typically has much better reliability, so weighting it six times worse seems inconsistent with improved reliability.

A previous Considerations of Comments stated that the value of 6000 was based on NERC’s document “Integrated Risk Assessment Approach – Refinement to Severity Risk Index. https://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf” However, the SRI does not actually address lines less than 200 kV. The SRI was written in 2011, based on TADS data available at the time. TADS did not include complete reliability information on lines less than 200 kV until 2014. Lines below 200 kV typically configured differently than lines above 200 kV, with lower voltage lines often directly serving load. The SRI equation includes terms for both lost transmission lines and for lost load. Since lower voltage lines are much more likely than higher voltage lines to directly serve load, extrapolating data from higher voltages will incorrectly categorize risk.

Likes 0

Dislikes 0

Response: Thank you for your comment. The SDT contends that the 6000 aggregate weighted value is appropriate and should include BES Transmission Lines below 200 kV. Additionally, the SDT addressed multiple-point (or multiple-tap) lines on page 33 of the CIP-002-6 supplemental material. Entities should be cognizant of the BES definition when applying this criterion.

Spencer Tacke - Modesto Irrigation District – 4

Answer	No
---------------	----

Document Name	
Comment	
In Section 2.12 , the phrase "...BES Transmission Lines with a..." should be revised to "...BES Transmission Lines and any other transmission lines operated at 60 kV and above with a..."	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The SDT asserts that the table accurately identifies the weighted values for applicable BES Transmission Lines. Transmission Lines operated at a voltage less than 100 kV do not contribute to the aggregate weighted value.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
I don't believe the standard was unclear before. I believe NERC, FERC, and Regional Entities were over reaching and should have been more reasonable and less overreaching. For instance:	
New IRC 2.12 does not need to say BES Transmission lines or Monitored and Controlled . CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says "All BES Facilities" it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line's capability to be included in an IRC 2.11 or 2.12 evaluation.	
I believe this is all being done because FERC incorrectly produced section 3 page 10 of https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf . FERC's report says "For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all "non-BES generation" in their calculations. Foot note 9."	

Footnote 9 on Page 10 says “CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms “BES Generation,” and “Non-BES Generation.” Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don’t need to! You don’t have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit!

In my view FERC’s footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only.

Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?"

Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets?

It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s).

It ironic that NERC recently had another Project recently up for Ballot “Moving Technical Rational Sections” out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.

Likes 0

Dislikes 0

Response: Thank you for your comment. The Project 2016-02 Modification to CIP Standards Drafting Team developed the revisions to criterion 2.12 based on feedback from industry stakeholders that participated in the NERC CIP V5 Transition Advisory Group. The group of stakeholders identified ambiguity as it relates to entities that perform the functional obligation of the Transmission Operator. Previously, BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as

medium impact. There was no threshold below which these systems could fall to be categorized as low impact. Criterion 2.12 was revised so TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below the medium impact threshold and be considered low impact. The table included in the SDT's proposed revision excludes Transmission Lines operated below 100 kV in accordance with the Bulk Electric System definition. The SDT thanks you for your comment regarding criterion 2.11, however the project 2016-02 SDT is not authorized to revise Criterion 2.11 in this project.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	
Comment	
We agree with the drafting team, but we believe that Criterion 2.12 should be expanded to include any Control Center that operates a Medium Impact substation should be considered Medium Impact BES Cyber System (BCS).	
Likes 0	
Dislikes 0	

Response: Thank you for your comment. The SDT asserts that Criterion 1.3 accurately categorizes BES Cyber Systems at Control Centers that perform the functional obligations of the Transmission Operator for substations that contain medium impact BES Cyber Systems. The BES Cyber Systems in the example provided would be categorized as high impact BES Cyber Systems.

Daniel Gacek - Exelon - 1

Answer Yes

Document Name

Comment

Exelon agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.

Likes 0

Dislikes 0

Response: Thank you for your comment.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.

Likes 0

Dislikes 0

Response: Please see the SDTs response to Westar Energy and Kansas City Power & Light support Edison Electric Institute's.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Southern Company agrees with the proposed modification and appreciates the establishment of a bright line criteria between Low and Medium Impact Control Centers. The proposed change provides Registered Entities clarity which will help ensure that they have properly and consistently classified their BES facilities and assets.

Likes 0

Dislikes 0

Response: Thank you for your comment.

Masunch Bussey - Duke Energy - 1,3,5,6 - SERC

Answer Yes

Document Name

Comment

Duke Energy generally agrees with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12.

Likes 0

Dislikes 0

Response: Thank you for your comment.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEl agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

See EEI comments.	
Likes 0	
Dislikes 0	
Response: Please see the SDTs response to EEI.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Quebec Production - 1,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

Marty Hostler - Northern California Power Agency - 5

Answer No

Document Name

Comment

Planned an unplanned language was never in the SAR and never should have been debated. And never should be. NERC/FERC was trying to take a GOP empirical operations based data IRC 2.11 and change it to an unproven theoretically based criteria (Planned Changes). Totally unreasonable over regulation attempts.

Please I praise the STD for reverting back to the old implementation plan. But it was changed a little bit or word order changes. Why couldn't language be really reverted back to current state" ?

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. The implementation plan was modified to reflect the CIP-002-5.1 implementation plan, with the addition of an example unplanned change.

Lana Smith - San Miguel Electric Cooperative, Inc. – 5

Answer No

Document Name

Comment

San Miguel agrees with comments submitted by NRECA.

Likes 0	
Dislikes 0	
Response: Please see the SDT's response to NRECA.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
<p>AECI supports comments filed by NRECA as such:</p> <p>NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the "Planned Changes" section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the "Initial Performance of Periodic Requirements" section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the "Initial Performance of Periodic Requirements" section be revised to state:</p> <p><i>"After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement."</i></p> <p>Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of "Planned" and "Unplanned" changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.</p>	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to NRECA.	

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio

Answer No

Document Name

Comment

NCEMC supports NRECA's Comments

Likes 0

Dislikes 0

Response: Please see the SDT's response to NRECA.

Barry Lawson - National Rural Electric Cooperative Association - 4

Answer No

Document Name

Comment

NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the "Planned Changes" section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the "Initial Performance of Periodic Requirements" section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the "Initial Performance of Periodic Requirements" section be revised to state:

"After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement."

Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of “Planned” and “Unplanned” changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.

Likes 0

Dislikes 0

Response: The language in the planned changes section refers to the initial performance section of the CIP Version 5 Implementation Plan. In reverting to the previous language based on comments, the standard drafting team copied the language from that plan for convenience, noting that, “The planned and unplanned change provisions in the Implementation Plan associated with CIP-002- 5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard).” As such, the language in the CIP-002-6 Implementation Plan is a reproduction of version5 with clarifying changes in the Planned and Unplanned Changes section that point back to the CIP-002-5 Implementation Plan. Due to the Planned and Unplanned Changes being outside the scope of our Standards Authorization Request (SAR), a new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference.

Andrea Barclay - Georgia System Operations Corporation - 4

Answer

No

Document Name

Comment

GSOC has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the planned changes section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the initial performance of certain periodic requirements appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, GSOC recommends that the initial performance of certain periodic requirements be revised to state:

After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement.

Likes 0

Dislikes 0

Response:

The language in the planned changes section refers to the initial performance section of the CIP Version 5 Implementation Plan. In reverting to the previous language based on comments, the standard drafting team copied the language from that plan for convenience, noting that, “The planned and unplanned change provisions in the Implementation Plan associated with CIP-002- 5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard).” As such, the language in the CIP-002-6 Implementation Plan is a reproduction of version5 with clarifying changes in the Planned and Unplanned Changes section that point back to the CIP-002-5 Implementation Plan.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

Yes

Document Name

Comment

We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

“Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity **and** subsequently identified through the annual assessment under CIP-002-6, Requirement R2.”

The “and” in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System’s compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comments. A more comprehensive look at the Planned and Unplanned Changes is outside the scope of our Standards Authorization Request (SAR). A new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference.

Clay Walker - Cleco Corporation - 1,3,5,6 – SERC

Answer

Yes

Document Name

Comment

See EEI comments.

Likes 0

Dislikes 0

Response: Please see the SDT’s response to EEI.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Yes

Document Name

Comment

: We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The proposed language for planned and unplanned changes in the current implementation planned removed the rigor to ensure that BES Cyber Systems that can impact the Bulk Electric System are compliant to the CIP Standards within the timeframes specified for planned or unplanned changes. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

“Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity **and** subsequently identified through the annual assessment under CIP-002-6, Requirement R2.”

The “and” in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System’s compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.

Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comments. Due to the Planned and Unplanned Changes being outside the scope of our Standards Authorization Request (SAR). A new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EI supports the proposed modification.

Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
PG&E appreciates the SDT reverting the Planned and Unplanned Changes back to the original CIP-005-5 conditions until an appropriate SAR can be proposed to address the conditions raised in the July 2019 CIP-002-6 comment and ballot.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Masunchu Bussey - Duke Energy - 1,3,5,6 – SERC	
Answer	Yes
Document Name	
Comment	
Duke Energy generally agrees with the proposed modifications. However, the speed in which solar sites are being built does not allow sufficient time to build physical security controls without delaying solar connection to the grid. Duke would like to see an implementation plan for newly build generation which allows the registered entity a specified amount of time (6 months) to complete compliance tasks and documentation.	

Duke Energy would like the unplanned change definition to include purchases of new generation as well. The registered entity knows the purchase is taking place, but the plant will need to be included in the Duke program after the purchase date.

Likes 0

Dislikes 0

Response: Thank you for your comment. This modification is outside the scope of our SAR. The team will consider this comment for the upcoming SAR to be submitted. These comments for that future project will be preserved as part of our project for reference.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer Yes

Document Name

Comment

Southern agrees with reverting this wording back to the “current state”. Moving this proposed change to a separate SAR will give the SDT and the industry much needed time to fully explore additional options and appropriately weigh any compliance risk associated with the change.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer Yes

Document Name

Comment

We agree with the change, however it should be clear that the implementation schedule is applicable to any of the unplanned change type listed on the table of CIP-002-6 on page 3 and is enforceable going forward, not just during transition from CIP-002-5.1a to CIP-002-6.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. The SDT agrees that the unplanned changes section is enforceable until CIP-002-6 is superseded or retired.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.

Likes 0

Dislikes 0

Response: Please see the SDT's response to EEI's comment.

Daniel Gacek - Exelon – 1

Answer Yes

Document Name

Comment

Exelon supports the proposed modification.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment.

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer

Yes

Document Name

Comment

The existing language from the CIP-002-5.1a Implementation Plan moved into the CIP-002-6 Implementation Plan provides shorter implementation periods than the Planned and Unplanned Changes section stricken from CIP-002-6 Draft 3. Specifically, Draft 3 provided 24 calendar months for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, whereas the new Implementation Plan only provides 12 months. The wording of Question 2 does not make that clear. Request industry be advised of this impact.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. The SDT issued the following statement in the request for comments: “Responses regarding the Planned and Unplanned changes section within CIP-002-6 were received from the June – July, 2019 comment and initial ballot period. Upon consideration of these comments and the issues raised, the drafting team determined that the matter of the CIP-002 identification and categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore, the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the Transmission Owner Control Center modifications and other minor

updates (i.e., removal of the retired term SPS, etc.).” An entity that identifies its first high impact or medium impact BES Cyber System due to an unplanned change is given 24 months to comply with the applicable CIP standards.

David Jendras - Ameren - Ameren Services – 3

Answer Yes

Document Name

Comment

Ameren supports EEI comments for this question; therefore we support the proposed modification.

Likes 0

Dislikes 0

Response: Please reference the SDT’s response to EEI.

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer Yes

Document Name

Comment

Reclamation supports the concept of different compliance implementation dates for planned versus unplanned changes. Reclamation recommends the compliance implementation date be calculated from the date the modified BES Cyber System is capable of impacting the BES. This will allow time for testing and returning existing equipment to service without the need to document compliance of equipment that is not capable of causing an adverse reliability impact.

Likes 0

Dislikes 0

Response: Thank you for your comment. This modification is outside the scope of our SAR. The team will consider this comment for the upcoming SAR to be submitted.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Quebec Production - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Kent Feliks - AEP – 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
<p>Texas RE recommends including additional examples under Planned Changes to include Generation Facilities and Control Centers. Responsible Entities have struggled with the interpretation of what <i>“upon the commissioning”</i> means.</p> <p>Texas RE noticed the following:</p> <ul style="list-style-type: none"> • “Responsible Entities” is capitalized throughout the Standard but not in the Implementation Plan. Texas RE recommends the term be capitalized and the language explaining “Responsible Entities” added for clarity and consistency. • In the table for “unplanned changes” the term “Medium-Impact” is capitalized/hyphenated and should not be for consistency. 	
Likes 0	
Dislikes 0	
<p>Response: The SDT thanks you for your comment. The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The noted capitalization issues have been resolved.</p>	

3. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

James Baldwin - Eugene Water and Electric Board - 1,3 - WECC

Answer No

Document Name

Comment

Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. The Project 2016-02 SDT modified CIP-003-7 as detailed in the Standards Authorization Request. Any further modifications are outside the scope of this project. (Add language on what we did and establishing the floor. See above.)

Daniel Gacek - Exelon – 1

Answer Yes

Document Name

Comment

Exelon supports the proposed modification in terms of the flexibility it provides to meet reliability objectives in a cost effective manner..

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer Yes

Document Name

Comment

Westar Energy and Kansas City Power & Light support Edison Electric Institute’s response.

Likes 0

Dislikes 0

Response: Please see the SDT’s response to EEI’s comment.

Masunch Bussey - Duke Energy - 1,3,5,6 – SERC

Answer Yes

Document Name

Comment

Duke Energy generally does not agree that the proposed modifications in CIP-002-6 are cost effective. Duke Energy generally does not agree that they pose a financial burden.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. As the proposed modifications allow for some entities of low impact to the BES to have their BES Cyber Systems in the low impact category, it is more cost effective for those entities. It is realized that the change affects a small number of entities, and for others who are not affected by the 2.12 criteria it can just be a documentation change that would have some cost.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson

Answer Yes

Document Name

Comment

As provided in PG&E comments as part of the July 2019 comment and ballot period, PG&E believes the 24 month time-frame is sufficient to apply the necessary Requirement changes when the impact rating goes from low to medium, or medium to high. While PG&E has not experienced changes in impact rating that would elevate a BCS impact rating, our experience on the application of the Requirements for medium and high BCS does not suggest a longer time-frame would be necessary.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer Yes

Document Name

Comment

none

Likes 0

Dislikes 0

Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes	0
Dislikes	0
Response	
Carl Pineault - Hydro-Quebec Production - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3

Answer Yes

Document Name

Comment

Likes 0

Dislikes 0

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer Yes

Document Name

Comment

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports EEI comments for this question; therefore we will not submit comments on cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
See EEI comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
No NERC needs to include real cost estimate. Take a look at a recent WECC Controls webinar and include those cost too in all standards.	
Likes 0	
Dislikes 0	
Response: The SDT cannot provide cost estimates since the costs are dependent on any entity's particular systems and architecture. This question is designed for the entity to use their knowledge of their infrastructure and provide feedback to NERC and the SDT on the cost impact of a proposed change. For this particular modification to CIP-002, criteria 2.12, the SDT has modified the criteria such that it allows some entities that are low impact to potentially move some BES Cyber Systems from medium to low impact and could actually result in a cost reduction for those entities.	

4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.

Marty Hostler - Northern California Power Agency - 5

Answer

Document Name

Comment

New IRC 2.12 does not need to say **BES** Transmission lines or **Monitored and Controlled**. CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says “All BES Facilities” it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line's capability to be included in an IRC 2.11 or 2.12 evaluation.

I believe this is all being done because FERC incorrectly produced section 3 page 10 of <https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf>. FERC's report says “For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all “non-BES generation” in their calculations. Foot note 9.” Footnote 9 on Page 10 says “CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms “BES Generation,” and “Non-BES Generation.” Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don't need to! You don't have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit!

In my view FERC's footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only.

Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?"

Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets?

It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s).

It ironic that NERC recently had another Project recently up for Ballot "Moving Technical Rational Sections" out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.

Likes 0

Dislikes 0

Response: Thank you for your comment. The Project 2016-02 Modification to CIP Standards Drafting Team developed the revisions to criterion 2.12 based on feedback from industry stakeholders that participated in the NERC CIP V5 Transition Advisory Group. The group of stakeholders identified ambiguity as it relates to entities that perform the functional obligation of the Transmission Operator. Previously, BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as medium impact. There was no threshold below which these systems could fall to be categorized as low impact. Criterion 2.12 was revised so TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below the medium impact threshold and be considered low impact. The table included in the SDT's proposed revision excludes Transmission Lines operated below 100 kV in accordance with the Bulk Electric System definition. The SDT thanks you for your comment regarding criterion 2.11, however the project 2016-02 SDT is not authorized to revise Criterion 2.11.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer

Document Name

Comment

NV Energy believes additional guidance is necessary regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0

Dislikes 0

Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer

Document Name

Comment

EI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6:

1. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)".
2. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's

Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.

3. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC’s Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
4. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6.
5. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.
6. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0

Dislikes 0

Response: Thank you for your comment. The team will note your edits and cleanup will take place during the virtualization modifications.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

Document Name

Comment

We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0	
Dislikes 0	
Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
We thank the SDT for allowing us to provide comments on these changes.	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
San Miguel appreciates the efforts of the SDT on this project.	
Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer

Document Name

Comment

AECI appreciates the efforts of the SDT on these issues.

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

Texas RE noticed the following:

- In the section “BES Cyber Systems”, there appears to be incorrect grammar in first sentence discussing transition.
- Starting on page 10, the footer information contains the incorrect draft version and date.

Likes 0

Dislikes 0

Response: Thank you for your comment. The version will be removed by the final ballot period and will no longer be shown.

Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch

Answer

Document Name

Comment

MISO supports the additional clarity provided in the Supplemental Material (on page 29, under "Medium Impact Rating" and page 38 under "Low Impact Rating"); i.e. "No additional evaluation is necessary for BES Cyber Systems that have already been identified as high (or medium) impact."

Likes 0

Dislikes 0

Response: Thank you.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

Comments: EEI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6:

1. Page 5 of the Redline, Section 6, Background, under subheading "BES Cyber Systems", the first word in the sentence (transitioning) needs to be capitalized.
2. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)".
3. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's Organization

Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.

4. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC’s Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
5. The footnote on all pages (i.e., page 10 moving forward) incorrectly still references Draft 3 of CIP-002-6.
6. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.
7. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0

Dislikes 0

Response Team will address during virtualization modification stage.

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio

Answer

Document Name

Comment

NCEMC appreciates the efforts of the SDT on these issues.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson

Answer

Document Name

Comment

PG&E provides no additional comments.

Likes 0

Dislikes 0

Response

Masunch Bussey - Duke Energy - 1,3,5,6 - SERC

Answer

Document Name

Comment

Duke Energy has the following additional comments - The second paragraph in Criterion 2.1 on page 29 of 45 states "to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024" The MOD-024 Standard has been retired and should be removed as a reference.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. This cleanup will be completed during the virtualization modifications.

Barry Lawson - National Rural Electric Cooperative Association – 4

Answer	
Document Name	
Comment	
NRECA appreciates the efforts of the SDT on these issues.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
While draft 3 provided additional time (24 calendar months) for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, Southern understands that removing the proposed change associated with “time frames to implement” while reverting to the previous language makes sense. We look forward to the opportunity to actively participate in addressing this as a part of a future proposed change which encompasses addressing planned and unplanned changes, as a whole.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	

Comment

Provide clearer examples for each of the listed items in the implementation table for the unplanned section.

Likes 0

Dislikes 0

Response: Thank you for your comment. The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project.

Carl Pineault - Hydro-Quebec Production - 1,5

Answer

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Daniel Gacek - Exelon - 1

Answer

Document Name

Comment

Exelon supports the comments offered by EEI, as reflected here:

1. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - “transitioning from Version 4 to Version 5” and “(as that term is used in Version 4)”.
2. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC’s Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.
3. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC’s Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
4. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6.
5. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.
6. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded

Likes 0	
Dislikes 0	
Response: Please see the SDT’s response to EEI’s comment.	
Kent Feliks - AEP – 3	
Answer	
Document Name	
Comment	

AEP has no additional comments at this time.

Likes 0

Dislikes 0

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer

Document Name

Comment

We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0

Dislikes 0

Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).

Anthony Jablonski - ReliabilityFirst – 10

Answer

Document Name	
Comment	
<p>The posted version has incorrect grammar in R1, Parts 1.1 and 1.2. Please change Part 1.1 from “Identify each of the high impact BES Cyber System” to “Identify each high impact BES Cyber System”. Please change Part 1.2 from “Identify each of the medium impact BES Cyber System” to “Identify each medium impact BES Cyber System”. Also please consider requiring explicit identification of associated systems (currently EACMS, PACS, PCA) for inclusion in the standard language (e.g. R1 P1.4) for high and medium impact BES Cyber Systems. Suggested wording: “Identify each EACMS, PACS, and PCA associated with a high impact BES Cyber System or a medium impact BES Cyber System.” This addition would serve to remind Responsible Entities that such identifications are required, and will permit assessing a violation, if applicable, against only one Requirement.</p>	
Likes 0	
Dislikes 0	
<p>Response: The SDT thanks you for your comment. Will be cleaned up during virtualization modifications.</p> <p>Outside the scope of this SAR and will be considered for a future project.</p>	
<p>Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran</p>	
Answer	
Document Name	
Comment	
<p>N/A</p>	
Likes 0	
Dislikes 0	
<p>Response</p>	

David Jendras - Ameren - Ameren Services - 3

Answer

Document Name

Comment

Ameren agrees with and supports EEI comments for this question.

Likes 0

Dislikes 0

Response: Please see the SDT's response to EEI.

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer

Document Name

Comment

Reclamation recommends the SDT add the definitions of Planned Changes and Unplanned Changes to the NERC Glossary of Terms.

Likes 0

Dislikes 0

Response: The SDT thanks you for your comment. The SDT will draft a SAR to address Planned/Unplanned Changes in a future project.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC

Answer

Document Name

Comment

None	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	
Document Name	
Comment	
ATC supports the commetns of EEI.	
Likes 0	
Dislikes 0	
Response: Please see the SDT’s response to EEI’s comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
I find the standard difficult to read with the various references back and forth between the Standard and Attachment 1. Ideally, the references should be mimized. This may be an issue in enforcement, and could cause some confusion to some entities.	
Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment. The requested changes are beyond the scope of the project.

End of report.

Standards Announcement

Reminder

Project 2016-02 Modifications to CIP Standards

Additional Ballot and Non-binding Poll Open through December 16, 2019

[Now Available](#)

The additional ballot and non-binding Poll for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, December 16, 2019**.

Responses regarding the Planned and Unplanned changes section within CIP-002-6 were received from the June – July, 2019 comment and initial ballot period. Upon consideration of these comments and the issues raised, the drafting team determined that the matter of the CIP-002 identification and categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore, the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the Transmission Owner Control Center modifications and other minor updates (i.e., removal of the retired term SPS, etc.).

Balloting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit votes. Contact [Wendy Muller](#) regarding issues using the SBS.

Note: Votes cast in the previous ballot will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to vote again in the additional ballot. NERC asks those not wanting to vote affirmative or negative cast an abstention to ensure a quorum is reached.

- Contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.
- Passwords expire every **6 months** and must be reset.
- The SBS **is not** supported for use on mobile devices.
- Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

[Subscribe to this project's observer mailing list](#) by selecting "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify "Project 2016-02 Modifications to CIP Standards Observer List" in the Description Box. For more information or assistance, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Formal Comment Period Open through December 16, 2019

[Now Available](#)

A 45-day formal comment period for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, December 16, 2019**.

Responses regarding the Planned and Unplanned changes section within CIP-002-6 were received from the July 2019 45-day comment and ballot period. Upon consideration of these comments and the issues raised, the drafting team determined that the matter of the CIP-002 identification and categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore, the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the TOCC modifications and other minor updates (i.e., removal of the retired term SPS, etc.).

Commenting

Use the [Standards Balloting and Commenting System \(SBS\)](#) to submit comments. Contact [Wendy Muller](#) regarding issues using the SBS. An unofficial Word version of the comment form is posted on the [project page](#).

- *Contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **December 6-16, 2019**.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

For more information or assistance, contact Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Comment: [View Comment Results](#)

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 AB 4 ST

Voting Start Date: 12/6/2019 12:01:00 AM

Voting End Date: 12/16/2019 8:00:00 PM

Ballot Type: ST

Ballot Activity: AB

Ballot Series: 4

Total # Votes: 294

Total Ballot Pool: 359

Quorum: 81.89

Quorum Established Date: 12/16/2019 4:26:34 PM

Weighted Segment Value: 95.98

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	94	1	70	0.986	1	0.014	0	7	16
Segment: 2	7	0.3	3	0.3	0	0	0	1	3
Segment: 3	84	1	65	0.985	1	0.015	0	2	16
Segment: 4	24	1	17	0.895	2	0.105	0	1	4
Segment: 5	84	1	66	0.985	1	0.015	0	3	14
Segment: 6	55	1	42	1	0	0	0	2	11
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	359	6.2	271	5.951	6	0.249	0	17	65

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Michael Lee		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Joel Limoges		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A

1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		Abstain	N/A
3	Piedmont EMC	Lawrence Hopkins Jr		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	None	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
5	WEC Energy Group, Inc.	Janet OBrien		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
1	Salt River Project	Chris Hofmann		None	N/A

5	AEP	Thomas Foltz		Affirmative N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative N/A
6	Austin Energy	Andrew Gallo		Affirmative N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative N/A
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro		Affirmative N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		Affirmative N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative N/A
1	Long Island Power Authority	Robert Ganley		Affirmative N/A
5	Seattle City Light	Faz Kasraie		Affirmative N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative N/A
5	Portland General Electric Co.	Ryan Olson		Abstain N/A
3	Portland General Electric Co.	Dan Zollner		Abstain N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None N/A
3	Cowlitz County PUD	Russell Noble		Affirmative N/A
6	Portland General Electric Co.	Daniel Mason		Abstain N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None N/A
5	Nebraska Public Power District	Don Schmit		Affirmative N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative N/A
5	Acciona Energy North America	George Brown		None N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative N/A
5	Talen Generation, LLC	Donald Lock		Affirmative N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative N/A

5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
4	Seattle City Light	Hao Li		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrold Murdaugh		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	None	N/A
2	California ISO	Jamie Johnson		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A

6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer	Affirmative N/A
5	Kissimmee Utility Authority	Jay Butters	Affirmative N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino	Affirmative N/A
5	Black Hills Corporation	George Tatar	Affirmative N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Affirmative N/A
1	New York Power Authority	Salvatore Spagnolo	Abstain N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	Affirmative N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative N/A
3	NW Electric Power Cooperative, Inc.	John Stickley	Affirmative N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert	Affirmative N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Affirmative N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Affirmative N/A
2	Midcontinent ISO, Inc.	David Zwergel	Affirmative N/A
1	Western Area Power Administration	sean erickson	Affirmative N/A
3	Manitoba Hydro	Karim Abdel-Hadi	Affirmative N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy	Affirmative N/A
3	Gainesville Regional Utilities	Darko Kovac	Affirmative N/A
1	Lakeland Electric	Larry Watt	None N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk	Affirmative N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell	Affirmative N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	None N/A
3	Black Hills Corporation	Eric Egge	Affirmative N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens	Affirmative N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin	Affirmative N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead	Affirmative N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace	None N/A
4	North Carolina Electric Membership Corporation	Luis Fondacci	Kagen DelRio Affirmative N/A
8	David Kiguel	David Kiguel	Affirmative N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative N/A
3	National Grid USA	Brian Shanahan	Affirmative N/A

3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	North Carolina Electric Membership Corporation	John Cook	Kagen DelRio	Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
1	Edison International - Southern California Edison Company	Ayman Samaan		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	LaGen	Wayne Messina		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A

1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		None	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		None	N/A
3	AEP	Kent Feliks		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Affirmative	N/A
6	Lakeland Electric	Paul Shipp		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	Intermountain REA	Pam Feuerstein		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Lower Colorado River Authority	Trey Melcher		Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A

3	Salt River Project	Zack Heim	None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
4	National Rural Electric Cooperative Association	Barry Lawson	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
1	Peak Reliability	Michael Granath	None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson	None	N/A
5	SunPower	Bradley Collard	None	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon	None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson	Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski	Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long	None	N/A
3	Eversource Energy	Sharon Flannery	Affirmative	N/A
1	JEA	Joe McClung	None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike O'Neil	Affirmative	N/A
6	New York Power Authority	Thomas Savin	Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	None	N/A

3	Imperial Irrigation District	Glen Allegranza		None	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
5	AES - AES Corporation	Leo Bernier		None	N/A
1	City of College Station	Stacy Lee		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
5	San Miguel Electric Cooperative, Inc.	Lana Smith		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
1	Prairie Power, Inc.	Dick Chapman		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Dwayne Parker		None	N/A

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 Non-binding Poll AB 4 NB

Voting Start Date: 12/6/2019 12:01:00 AM

Voting End Date: 12/16/2019 8:00:00 PM

Ballot Type: NB

Ballot Activity: AB

Ballot Series: 4

Total # Votes: 268

Total Ballot Pool: 332

Quorum: 80.72

Quorum Established Date: 12/16/2019 4:34:18 PM

Weighted Segment Value: 97.74

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	54	0.982	1	0.018	15	15
Segment: 2	7	0.3	3	0.3	0	0	1	3
Segment: 3	80	1	53	0.964	2	0.036	9	16
Segment: 4	20	1	13	0.929	1	0.071	3	3
Segment: 5	78	1	52	0.981	1	0.019	9	16
Segment: 6	51	1	34	1	0	0	7	10
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 1	1	0.1	1	0.1	0	0	0	0

9

Segment:	7	0.4	4	0.4	0	0	3	0
10								
Totals:	332	6	216	5.855	5	0.145	47	64

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Joel Limoges		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A

1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	None	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
1	Salt River Project	Chris Hofmann		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A

6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Abstain	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
5	Acciona Energy North America	George Brown		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A

3	Exelon	Kinte Whitehead		Affirmative N/A
5	Exelon	Cynthia Lee		Affirmative N/A
6	Exelon	Becky Webb		Affirmative N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative N/A
1	Seattle City Light	Pawel Krupa		None N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative N/A
4	Modesto Irrigation District	Spencer Tacke		None N/A
4	Seattle City Light	Hao Li		Affirmative N/A
5	Duke Energy	Dale Goodwine		Affirmative N/A
6	Duke Energy	Greg Cecil		Affirmative N/A
3	Duke Energy	Lee Schuster		Affirmative N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative N/A
6	Muscatine Power and Water	Nick Burns		Affirmative N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative N/A
3	Ameren - Ameren Services	David Jendras		Abstain N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative N/A
3	Sho-Me Power Electric Cooperative	Jarrold Murdaugh		Affirmative N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	None	N/A
2	California ISO	Jamie Johnson		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative N/A
1	Western Area Power Administration	sean erickson		Affirmative N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative N/A
3	Gainesville Regional Utilities	Darko Kovac		Abstain N/A
1	Lakeland Electric	Larry Watt		None N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None N/A
3	Black Hills Corporation	Eric Egge		Affirmative N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Abstain N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative N/A
4	North Carolina Electric Membership Corporation	Luis Fondacci	Kagen DelRio	Affirmative N/A
8	David Kiguel	David Kiguel		Affirmative N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative N/A
3	National Grid USA	Brian Shanahan		Affirmative N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative N/A
1	Ameren - Ameren Services	Eric Scott		Abstain N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative N/A
5	JEA	John Babik		Affirmative N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative N/A
3	JEA	Garry Baker		None N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative N/A

1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		None	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	AEP	Kent Feliks		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A

5	Oglethorpe Power Corporation	Donna Johnson	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
1	Lower Colorado River Authority	Trey Melcher	Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Abstain	N/A
1	Santee Cooper	Chris Wagner	Affirmative	N/A
6	Santee Cooper	Michael Brown	Affirmative	N/A
3	Santee Cooper	James Poston	Affirmative	N/A
5	Santee Cooper	Tommy Curtis	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell	Abstain	N/A
3	Salt River Project	Zack Heim	None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
1	Peak Reliability	Michael Granath	None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner	Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson	None	N/A
5	SunPower	Bradley Collard	None	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra	Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver	Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson	Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski	Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long	None	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco	Affirmative	N/A
3	Eversource Energy	Sharon Flannery	Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike O'Neil	Affirmative	N/A
6	New York Power Authority	Thomas Savin	Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver	Affirmative	N/A

				Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Negative
5	Avista - Avista Corporation	Glen Farmer		Affirmative N/A
6	Imperial Irrigation District	Diana Torres		None N/A
3	Imperial Irrigation District	Glen Allegranza		None N/A
5	Entergy	Jamie Prater		Affirmative N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None N/A
5	Imperial Irrigation District	Tino Zaragoza		None N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative N/A
3	Lakeland Electric	Patricia Boody		Affirmative N/A
5	AES - AES Corporation	Leo Bernier		None N/A
1	City of College Station	Stacy Lee		Affirmative N/A
1	Southern Illinois Power Cooperative	William Hutchison		Affirmative N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative N/A
1	Great River Energy	Gordon Pietsch		Affirmative N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative N/A
5	San Miguel Electric Cooperative, Inc.	Lana Smith		Affirmative N/A
3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	Affirmative N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None N/A
3	Great River Energy	Brian Glover		Affirmative N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative N/A
6	Omaha Public Power District	Joel Robles		Affirmative N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative N/A
1	Prairie Power, Inc.	Dick Chapman		Affirmative N/A
5	California Department of Water Resources	ASM Mostafa		None N/A

5	Manitoba Hydro	Yuguang Xiao	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Dwayne Parker	None	N/A



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	June 3 – July 18, 2019
45-day formal comment period with additional ballot	November 1 – December 16, 2019
10-day final ballot	February 2020

Anticipated Actions	Date
NERC Board	May 2020

A. Introduction

1. **Title:** Cyber Security – BES Cyber System Categorization
2. **Number:** CIP-002-6
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. Balancing Authority
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.:

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3.1. Exemptions: The following are exempt from Standard CIP-002-5.1a:

- 4.2.3.2. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
 - 4.2.3.3. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
 - 4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
 - 4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.
5. **Effective Date:** See Implementation Plan for CIP-002-6.
6. **Background:** This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard. Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)**– Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples include, to the extent they are within the ESP: file servers, FTP servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
 - 1.1.** Identify each of the high impact BES Cyber System according to Attachment 1, Section 1, if any, at each asset;
 - 1.2.** Identify each of the medium impact BES Cyber System according to Attachment 1, Section 2, if any, at each asset; and
 - 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** Each Responsible Entity shall: [*Violation Risk Factor: Lower*][*Time Horizon: Operations Planning*]
- 2.1.** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2.** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

- None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber</p>

	<p>Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
<p>R2.</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of</p>

	<p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>
--	---	---	---	--

D. Regional Variances

None.

E. Associated Documents

- See Implementation Plan for CIP-002-6.
- See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	

CIP-002-6 – Cyber Security - BES Cyber System Categorization

5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD	Criteria for 2.12 was modified	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding

(UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

- 2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12. Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.13. Each Control Center or backup Control Center, not already included in High Impact Rating above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1. Control Centers and backup Control Centers.
- 3.2. Transmission stations and substations.
- 3.3. Generation resources.
- 3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6.

The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements

or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding

- Ability to identify load change need (BA)
- Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)

- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with

equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is “to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.” In particular, it requires that “as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency.” The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a “long term” reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as

“Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in Attachment 1 of NERC's "[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)", document, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems

and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers , that monitor and control BES Transmission lines with an aggregated weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

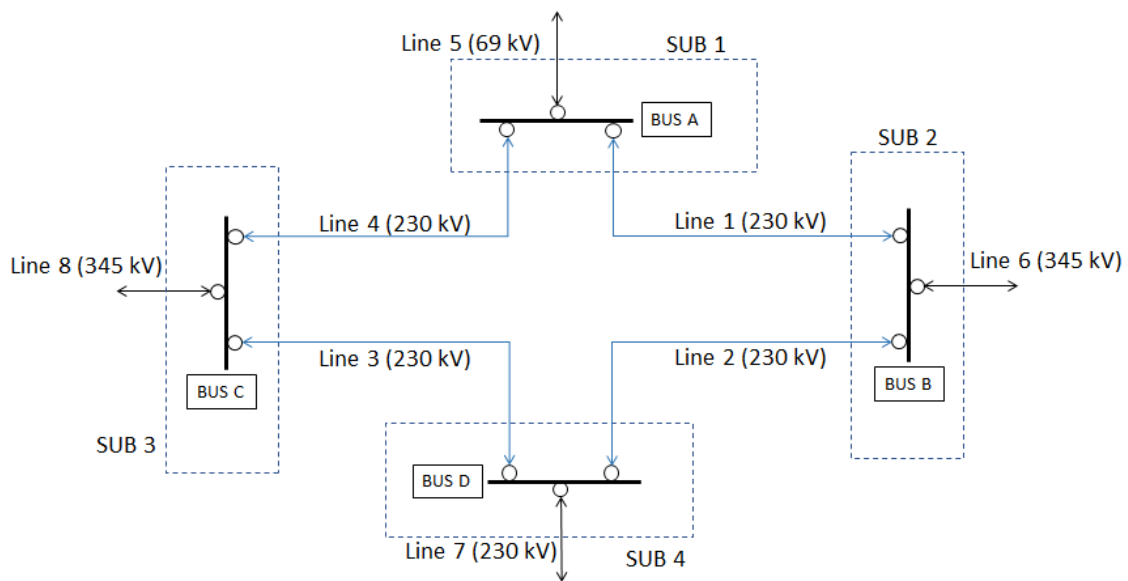
The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

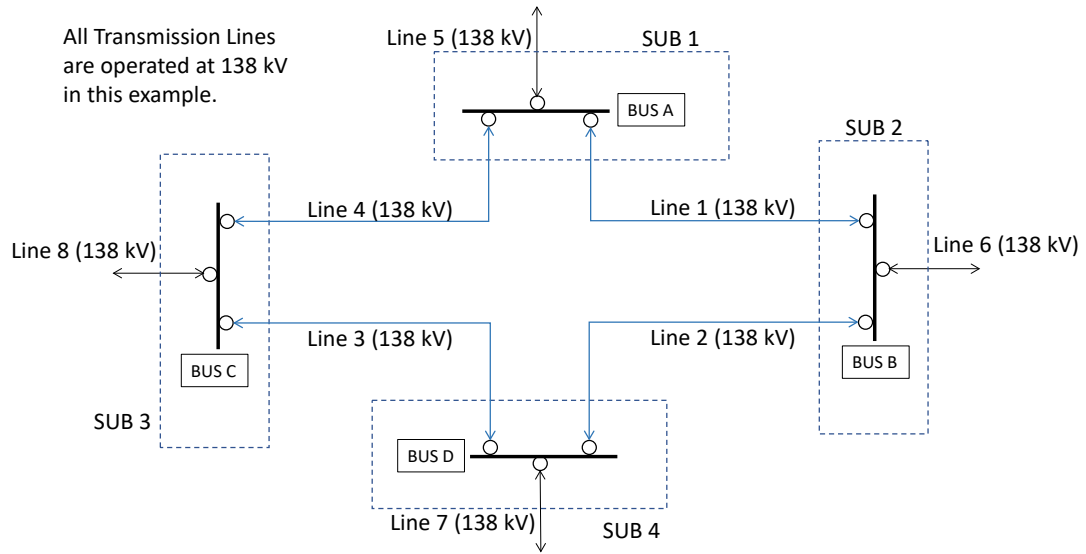
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as a low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

$$250+250+250+250+250+250+250+250= 2000$$

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator’s restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator’s restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to “provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.”

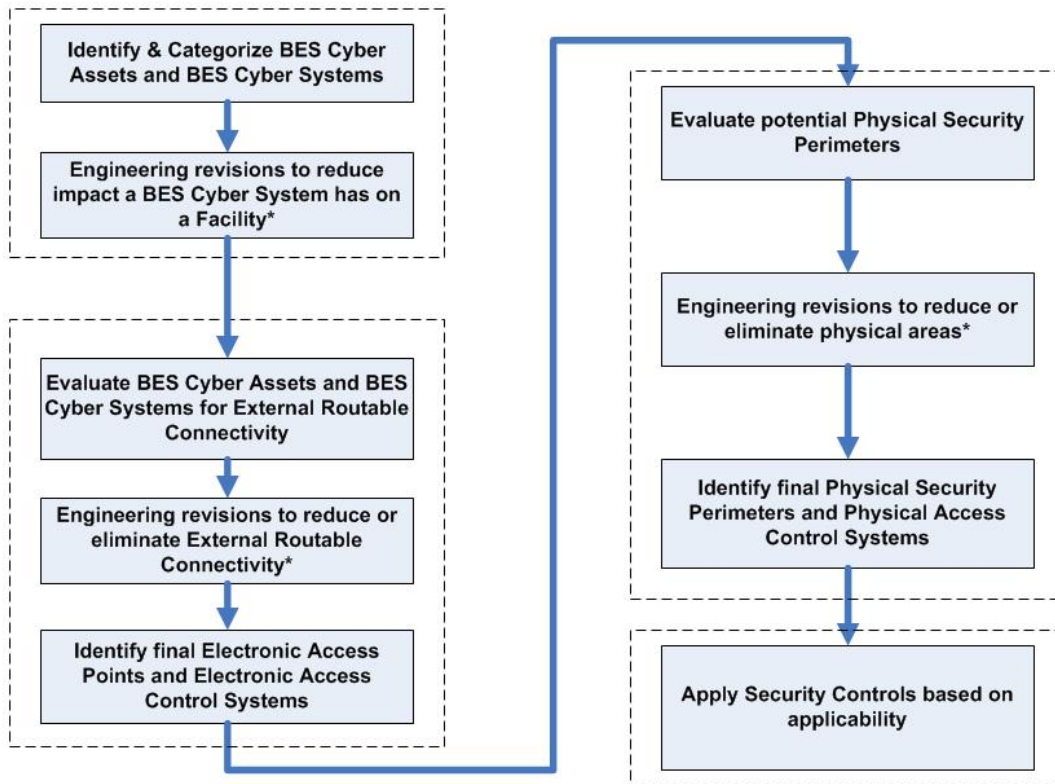
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator’s restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator’s Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational safety requirements, support requirements, and technical limitations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- a. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	March 14, 2017 – April 11, 2017
45-day formal comment period with initial ballot	September 14 – October 30, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	June 3 – July 18, 2019
45-day formal comment period with additional ballot	November 1 – December 16, 2019
10-day final ballot	January 24 – February 3 , 2020

Anticipated Actions	Date
NERC Board	May 2020

A. Introduction

1. **Title:** Cyber Security – BES Cyber System Categorization
2. **Number:** CIP-002-~~65.1a~~
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. Balancing Authority
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~**4.1.6.4.1.5. Reliability Coordinator**~~

~~**4.1.7.4.1.6. Transmission Operator**~~

~~**4.1.8.4.1.7. Transmission Owner**~~

4.2. Facilities For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.:

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3.1. Exemptions: The following are exempt from Standard CIP-002-5.1a:

4.2.3.2. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.3. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Date: See Implementation Plan for CIP-002-6.

~~1. **24 Months Minimum** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

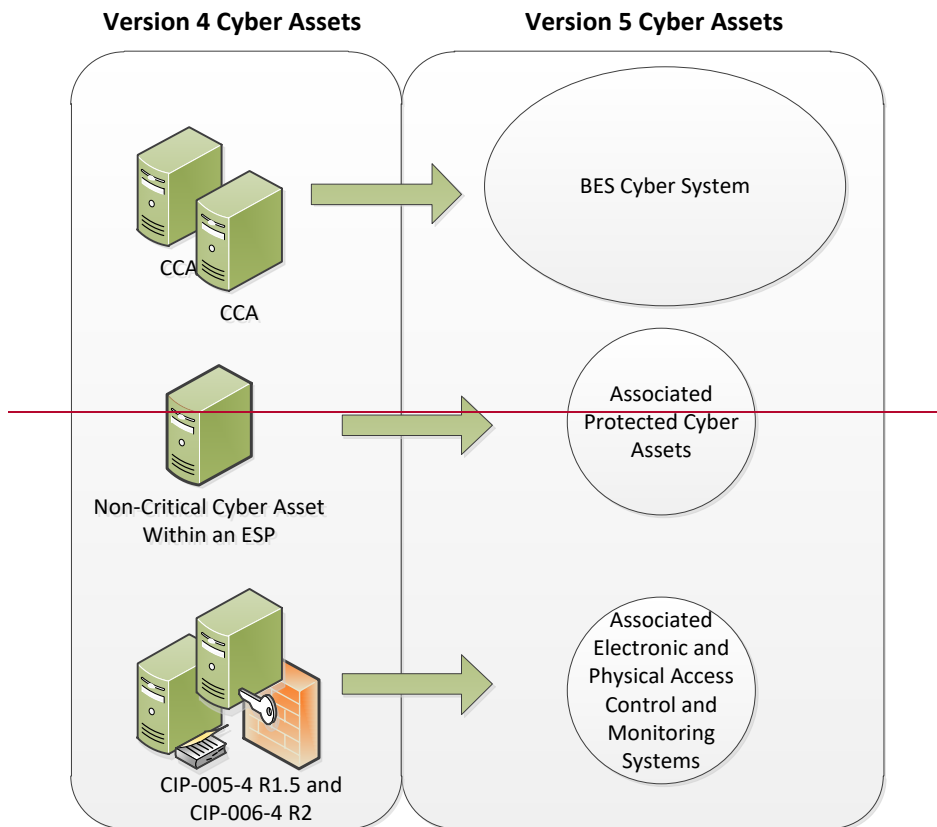
6. Background: This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.~~



~~In t~~Transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these ~~Version 5~~ CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement R1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, ~~Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11~~ Section 1 or Section 2, and listed in Section 3 default to ~~be~~ low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the ~~Version 5~~-CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

- **Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.
- **Physical Access Control Systems (“PACS”)**– Examples include: authentication servers, card systems, and badge control systems.
- **Protected Cyber Assets (“PCA”)** – Examples ~~may~~ include, to the extent they are within the ESP: file servers, ~~ftp-FTP~~ servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i. Control Centers and backup Control Centers;
 - ii. Transmission stations and substations;
 - iii. Generation resources;
 - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v. ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
 - 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
 - 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.
- R2.** ~~The Each~~ Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
 - 2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.
- M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and ~~Assessment Enforcement Program Processes:~~ As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot-Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

1.4. Additional Compliance Information

- None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES</p>

	<p>Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>
R2.	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of</p>

	<p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>
--	---	---	---	--

D. Regional Variances

None.

E. Associated Documents

- [See Implementation Plan for CIP-002-6.](#)
- [See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.](#)

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	<p>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</p> <p>Removal of reasonable business judgment.</p> <p>Replaced the RRO with the RE as a Responsible Entity.</p> <p>Rewording of Effective Date.</p> <p>Changed compliance monitor to Compliance Enforcement Authority.</p>	
3	12/16/09	<p>Updated version number from -2 to -3.</p> <p>Approved by the NERC Board of Trustees.</p>	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata

CIP-002-~~5.1a~~6 – Cyber Security – BES Cyber System Categorization

5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD	<u>Criteria for 2.12 was modified</u>	

~~CIP-002-5.1a~~ – Attachment 1

~~Impact Rating Criteria~~

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating ~~(H)~~

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating ~~(M)~~

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12. ~~Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~ Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>
<u>less than 100 kV (not applicable)</u>	<u>(not applicable)</u>
<u>100 kV to 199 kV</u>	<u>250</u>
<u>200 kV to 299 kV</u>	<u>700</u>
<u>300 kV to 499 kV</u>	<u>1300</u>
<u>500 kV and above</u>	<u>0</u>

- 2.13. Each Control Center or backup Control Center, not already included in High Impact Rating ~~(H)~~ above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating ~~(L)~~

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1. Control Centers and backup Control Centers.
- 3.2. Transmission stations and substations.

- 3.3. Generation resources.
- 3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5. ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1a6

CIP-002-5.1a6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a6. The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)

- Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO, TOP, GO, GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)

- Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)

- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA, TOP, GOP, RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better

served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high impact.

Generation

The criteria in Attachment 1’s medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is “to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.” In particular, it requires that “as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency.” The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities’ qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a “long term” reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as “Reliability Must Run,” and this designation is distinct from those generation Facilities designated as “must run” for market stabilization purposes. Because the use of the term “must run” creates some confusion in many areas, the drafting team chose to avoid using

this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in [Attachment 1 of NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index"](#), ~~document, Attachment 1,~~ the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those ~~Special Protection Systems (SPS)~~, Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a , that monitor and control BES Transmission Operator lines with an aggregated weighted value of 6000 or higher, and that have not already been categorized as high impact included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.~~

~~The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission~~

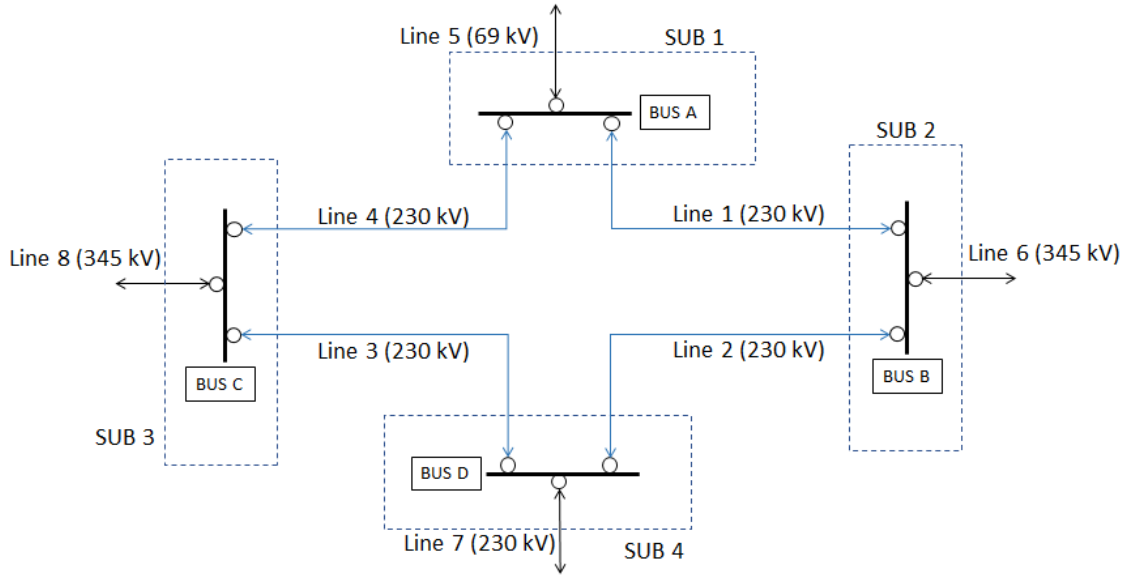
Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

-Criterion 2.12 Examples:

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

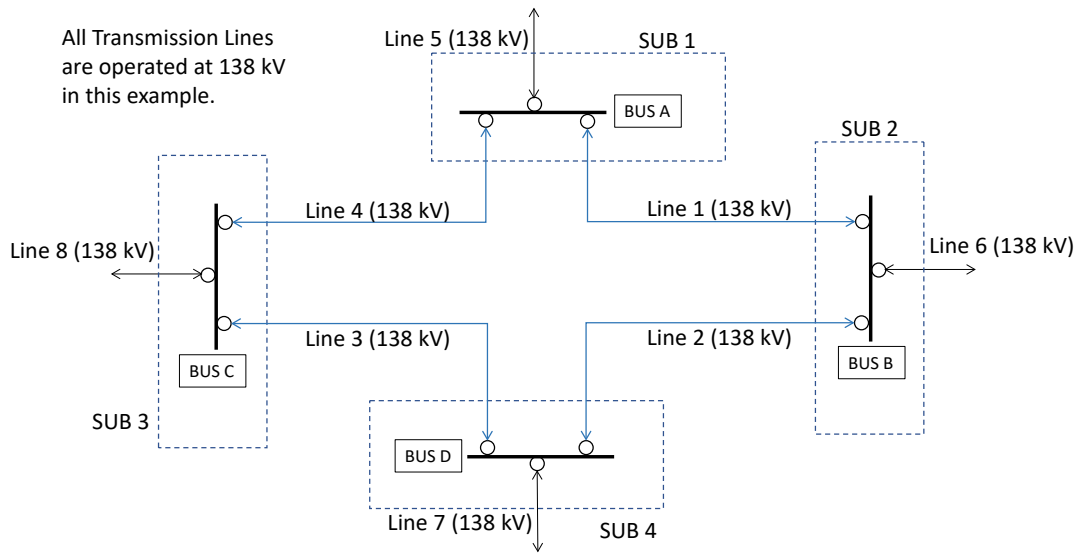
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>Line 5</u>	<u>N/A</u>
<u>100 kV to 199 kV</u>	<u>250</u>	<u>None</u>	<u>0</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>Line 1, Line 2, Line 3,</u> <u>Line 4, Line 7</u>	<u>3500</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>Line 6, Line 8</u>	<u>2600</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

$$700+700+700+700+700+1300+1300 = 6100$$

In the additional example below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as high impact—a low impact BES Cyber System(s) pursuant to Criterion 3.1.

<u>Voltage Value of a Line</u>	<u>Weight Value per Line</u>	<u>Applicable Lines</u>	<u>Weighted Value</u>
<u>less than 100 kV</u> <u>(not applicable)</u>	<u>(not applicable)</u>	<u>None</u>	<u>N/A</u>

<u>100 kV to 199 kV</u>	<u>250</u>	<u>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</u>	<u>2000</u>
<u>200 kV to 299 kV</u>	<u>700</u>	<u>None</u>	<u>0</u>
<u>300 kV to 499 kV</u>	<u>1300</u>	<u>None</u>	<u>0</u>
<u>500 kV and above</u>	<u>0</u>	<u>None</u>	<u>0</u>

Calculation

250+250+250+250+250+250+250+250= 2000

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

No additional evaluation is necessary for BES Cyber Systems that have already been identified as high or medium impact. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Section 1 or Section 2, and listed in Section 3 default to low impact. BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification, only identification of the asset containing the low impact BES Cyber System(s).

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to

categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

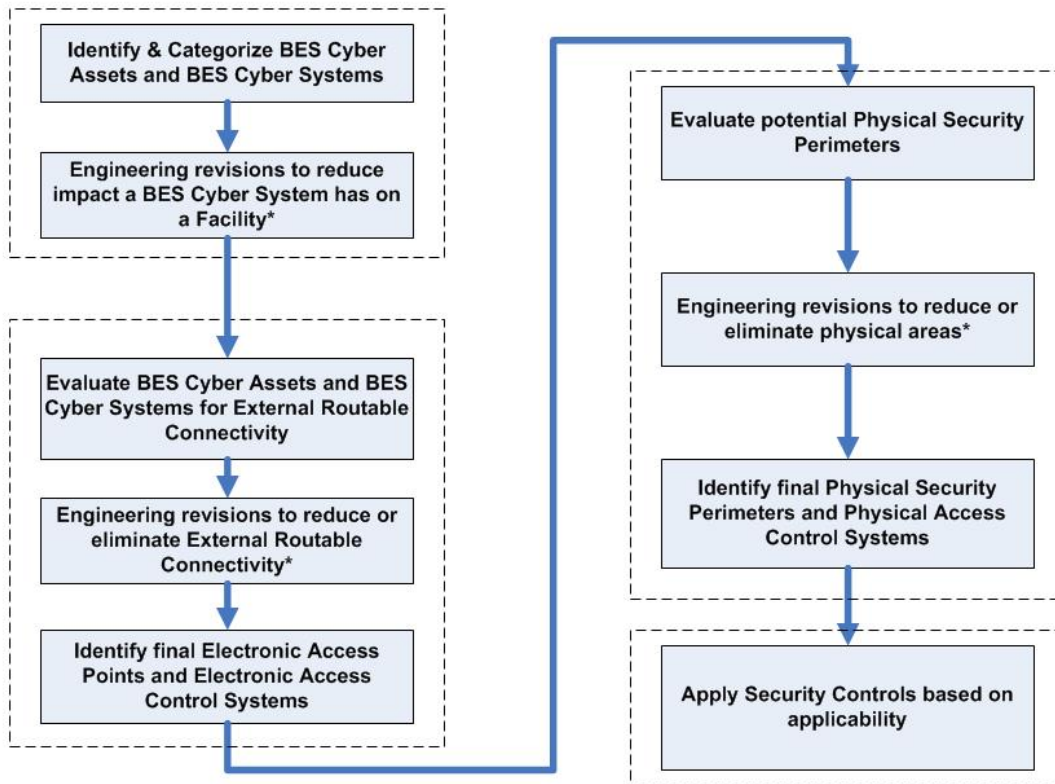
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

- i. Control Centers and backup Control Centers;
- ii. Transmission stations and substations;
- iii. Generation resources;
- iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
- vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

- 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
- 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
- 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- a. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “*Each BES Cyber System...associated with any of the following [criteria].*” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term “shared” is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.” For criterion 2.2: “BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security - BES Cyber System Categorization

Prerequisite Standard(s) or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

This Implementation Plan includes phased-in implementation dates for Criterion 2.12 of CIP-002-6, Attachment 1. The phased-in implementation dates allow Responsible Entities¹ a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion of it),

¹ As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter immediately after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 of Attachment 1 to CIP-002-6 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For *planned* changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* of the CIP-002-5.1a Implementation Plan.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *unplanned* changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* of the CIP-002-5.1a Implementation Plan.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2016-02 Modifications to CIP Standards Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization

Prerequisite Standard(s) or Definitions

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

This Implementation Plan includes ~~a~~ phased-in implementation dates for Criterion 2.12 of CIP-002-6, Attachment 1. The phased-in implementation dates allow Responsible Entities¹ a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion of it),

¹ As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter immediately after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 of Attachment 1 to CIP-002-6 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For *planned* changes resulting in a higher categorization, the ~~r~~Responsible ~~e~~Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* ~~above of the CIP-002-5.1a Implementation Plan~~.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the ~~r~~Responsible ~~e~~Entity and subsequently identified through the annual assessment under CIP-002-6, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *unplanned* changes resulting in a higher categorization, the ~~r~~Responsible ~~e~~Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* ~~above of the CIP-002-5.1a Implementation Plan~~.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to M Medium- i impact BES Cyber Systems

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
Newly categorized medium impact BES Cyber System	12 months
Responsible eEntity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible eEntity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

Standards Announcement

Project 2016-02 Modifications to CIP Standards

Final Ballot Open through April 6, 2020

[Now Available](#)

The 10-day final ballot for **CIP-002-6 - Cyber Security – BES Cyber System Categorization** is open through **8 p.m. Eastern, Monday, April 6, 2020.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pools associated with this project can log in and submit their vote [here](#). Contact [Wendy Muller](#) regarding issues using the Standards Balloting and Commenting System (SBS).

- Contact NERC IT support directly at <https://support.nerc.net/> (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.
- Passwords expire every **6 months** and must be reset.
- The SBS is **not** supported for use on mobile devices.
- Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the [Standard Processes Manual](#).

[Subscribe to this project's observer mailing list](#) by selecting "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify "Project 2016-02 Modifications to CIP Standards Observer List" in the Description Box. For more information or assistance, contact Senior Standards Developer, [Jordan Mallory](#) (via email) or at (404) 446-2589.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[NERC Balloting Tool](#)

- [Dashboard](#)
- [Users](#)
 - [Registered Ballot Body](#)
 - [Proxy Ballot Body](#)
 - [My User Profile](#)
- [Ballots](#)
 - [Ballot Events](#)
 - [Ballot Results](#)
- [Comment Forms](#)
 - [View Comment Forms](#)

[Login](#) / [Register](#)

Ballot Results

Ballot Name: 2016-02 Modifications to CIP Standards CIP-002-6 FN 5 ST

Voting Start Date: 3/26/2020 12:01:42 PM

Voting End Date: 4/6/2020 8:00:00 PM

Ballot Type: ST

Ballot Activity: FN

Ballot Series: 5

Total # Votes: 313

Total Ballot Pool: 356

Quorum: 87.92

Quorum Established Date: 3/26/2020 3:58:33 PM

Weighted Segment Value: 96.28

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	93	1	76	0.987	1	0.013	0	6	10
Segment: 2	7	0.6	6	0.6	0	0	0	0	1
Segment: 3	83	1	67	0.985	1	0.015	0	2	13
Segment: 4	24	1	18	0.9	2	0.1	0	1	3
Segment: 5	84	1	71	0.986	1	0.014	0	3	9
Segment: 6	54	1	46	1	0	0	0	2	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	356	6.5	292	6.258	6	0.242	0	15	43

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Cleco Corporation	Robert Hirschak	Louis Guidry	Affirmative	N/A
3	Xcel Energy, Inc.	Joel Limoges		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
5	TECO - Tampa Electric Co.	Dave Pickles		Abstain	N/A
3	Piedmont EMC	Lawrence Hopkins		None	N/A

		Jr		
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative N/A
3	City of Vero Beach	Ginny Beigel		None N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Affirmative N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Affirmative N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative N/A
6	Colorado Springs Utilities	Melissa Brown		None N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative N/A
1	Network and Security Technologies	Nicholas Lauriat		Affirmative N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative N/A
5	WEC Energy Group, Inc.	Janet OBrien		Affirmative N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative N/A
6	Seattle City Light	Charles Freeman		Affirmative N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative N/A
3	Seattle City Light	Laurie Hammack		None N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative N/A
1	Salt River Project	Chris Hofmann		Affirmative N/A
5	AEP	Thomas Foltz		Affirmative N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative N/A
6	Austin Energy	Andrew Gallo		Affirmative N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative N/A

6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative N/A
4	Silicon Valley Power - City of Santa Clara	Jeff Ipsaro		Affirmative N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		Affirmative N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative N/A
1	Long Island Power Authority	Robert Ganley		Affirmative N/A
5	Seattle City Light	Faz Kasraie		Affirmative N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative N/A
5	Portland General Electric Co.	Ryan Olson		Abstain N/A
3	Portland General Electric Co.	Dan Zollner		Abstain N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative N/A
5	Great River Energy	Jacalynn Bentz		Affirmative N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None N/A
3	Cowlitz County PUD	Russell Noble		Affirmative N/A
6	Portland General Electric Co.	Daniel Mason		Abstain N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative N/A
5	Acciona Energy North America	George Brown		None N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative N/A
1	Eversource Energy	Quintin Lee		Affirmative N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative N/A
5	Talen Generation, LLC	Donald Lock		Affirmative N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative N/A
3	Modesto Irrigation District	Roderick Cook		None N/A
6	Modesto Irrigation District	James McFall		None N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative N/A
1	Exelon	Daniel Gacek		Affirmative N/A
3	Exelon	Kinte Whitehead		Affirmative N/A
5	Exelon	Cynthia Lee		Affirmative N/A

6	Exelon	Becky Webb		Affirmative N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative N/A
1	Seattle City Light	Pawel Krupa		None N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative N/A
4	Modesto Irrigation District	Spencer Tacke		Negative N/A
4	Seattle City Light	Hao Li		Affirmative N/A
5	Duke Energy	Dale Goodwine		Affirmative N/A
6	Duke Energy	Greg Cecil		Affirmative N/A
3	Duke Energy	Lee Schuster		Affirmative N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative N/A
6	Muscatine Power and Water	Nick Burns		Affirmative N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative N/A
3	Ameren - Ameren Services	David Jendras		Affirmative N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative N/A
3	Sho-Me Power Electric Cooperative	Jarrold Murdaugh		Affirmative N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative N/A
5	New York Power Authority	Shivaz Chopra		Affirmative N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative N/A

1	Duke Energy	Laura Lee		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		Affirmative	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	None	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
5	Black Hills Corporation - Black Hills Power	Don Stahl		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A

1	Western Area Power Administration	sean erickson		Affirmative N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative N/A
3	Gainesville Regional Utilities	Darko Kovac		Affirmative N/A
1	Lakeland Electric	Larry Watt		None N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative N/A
3	Black Hills Corporation	Eric Egge		Affirmative N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative N/A
4	North Carolina Electric Membership Corporation	Luis Fondacci	Kagen DelRio	Affirmative N/A
8	David Kiguel	David Kiguel		Affirmative N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative N/A
3	National Grid USA	Brian Shanahan		Affirmative N/A
3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	Affirmative N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative N/A
5	North Carolina Electric Membership Corporation	John Cook	Kagen DelRio	Affirmative N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative N/A
5	JEA	John Babik		Affirmative N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative N/A
3	JEA	Garry Baker		None N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative N/A
1	Black Hills Corporation	Wes Wingen		Affirmative N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative N/A

5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
4	LaGen	Wayne Messina		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
1	Hydro-Quebec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Rick Meadows		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		None	N/A
3	AEP	Kent Feliks		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Affirmative	N/A
6	Lakeland Electric	Paul Shipp		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	Intermountain REA	Pam Feuerstein		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd	Affirmative N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Affirmative N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative N/A
1	Lower Colorado River Authority	James Baldwin	Abstain N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence	None N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	Affirmative N/A
5	Platte River Power Authority	Tyson Archie	Affirmative N/A
1	Nebraska Public Power District	Jamison Cawley	Affirmative N/A
1	Santee Cooper	Chris Wagner	Affirmative N/A
6	Santee Cooper	Marty Watson	Affirmative N/A
3	Santee Cooper	James Poston	Affirmative N/A
5	Santee Cooper	Tommy Curtis	Affirmative N/A
5	Lower Colorado River Authority	Teresa Cantwell	Abstain N/A
3	Salt River Project	Zack Heim	Affirmative N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	Affirmative N/A
5	City of Independence, Power and Light Department	Jim Nail	Affirmative N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich	Affirmative N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse	Affirmative N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative N/A
4	National Rural Electric Cooperative Association	Barry Lawson	Affirmative N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative N/A
1	Peak Reliability	Michael Granath	None N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative N/A
1	Glencoe Light and Power Commission	Terry Volkmann	Affirmative N/A
5	Bonneville Power Administration	Scott Winner	Affirmative N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative N/A
1	LS Power Transmission, LLC	Darin Ferguson	None N/A
5	SunPower	Bradley Collard	None N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	Affirmative N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver	Affirmative N/A
5	Orlando Utilities Commission	Dania Colon	None N/A
	Public Utility District No. 2 of Grant County,		

6	Washington	LeRoy Patterson		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long		None	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
1	JEA	Joe McClung		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Negative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
5	AES - AES Corporation	Leo Bernier		None	N/A
1	City of College Station	Stacy Lee		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
5	San Miguel Electric Cooperative, Inc.	Lana Smith		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
1	Prairie Power, Inc.	Dick Chapman		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A

5	Manitoba Hydro	Yuguang Xiao	Affirmative N/A
4	CMS Energy - Consumers Energy Company	Dwayne Parker	Affirmative N/A



Exhibit F

Transmission Owner Control Center White Paper

Considerations for Transmission Owner (TO) Control Centers (TOCC) with Capability to Perform Transmission Operator (TOP) Obligations

Project 2016-02 Modifications to CIP Standards

March 14, 2017

Introduction

The “TOCC White Paper” provides background and technical considerations for potential approaches to modifying the applicability of North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Reliability Standards as they relate to the protection of BES Cyber System(s) at Transmission Owner Control Centers performing the functional obligations of a Transmission Operator. The TOCC White Paper was drafted by the standard drafting team (“SDT”) for NERC Project 2016-02 Modifications to CIP Standards (Project 2016-02) for stakeholder consideration and comment. The TOCC White Paper has not been approved or endorsed by NERC. The SDT is using the TOCC White Paper as a standard development tool to collect feedback on the basis for revisions to the CIP standards on this issue, if any.

As outlined in the applicable Standards Authorization Request (SAR), NERC Project 2016-02, addresses the Federal Energy Regulatory Commission (FERC or Commission) Order No. 822 directives and the issues captured in the Version 5 Transition Advisory Group’s (V5TAG) *CIP V5 Issues for Standard Drafting Team Consideration* ([V5TAG Transfer Document](#)). The V5TAG, comprised of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. In the Transfer Document, the V5TAG outlined the issues which it believed required further modification or clarification within the CIP Reliability Standards. The necessary modifications were believed to support effective implementation; critical infrastructure security improvements; and/or consistency in Compliance Monitoring and Enforcement outcomes.

Among other things, the V5TAG Transfer Document proposes that the CIP SDT address the applicability of the CIP Reliability Standards to BES Cyber System(s) for a TO Control Center performing the functional obligations of a TOP. As such, the SAR for Project 2016-02 lists the following issues for the Project 2016-02 SDT to address:

1. The applicability of requirements on a TO’s Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the Bulk Electric System (BES);
2. The definition of Control Center; and

3. The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

To address the issues listed, the SDT identified the following five areas for examination and discussion: (1) the TOCC responsibilities as they relate to TOP functions or tasks within the NERC registration processes; (2) the roles that entity impact analyses and risk assessments play, including the NERC proposed beta criteria; (3) understanding of the phrase "performing functional obligations;" (4) a technical discussion on the capability vs. authority and span of control of BES Cyber System(s) associated with TOCCs; and (5) consideration of potential solutions. Each of these areas is discussed in this TOCC White Paper.

The SDT is seeking stakeholder feedback on its assessment of the TOCC issue area through the associated informal comment form. In particular, the SDT seeks feedback on the potential solutions proposed in this TOCC White Paper as well as any suggestions for alternative solutions.

V5TAG Background

As described in the NERC Project 2016-02 Standards Drafting Team SAR encompassing the V5TAG transfer document issues, there were multiple readings of the language “used to perform the functional obligation of” in CIP-002-5.1a, Attachment 1, criterion 2.12 and recommendations for clarification of:

- The applicability of requirements on a TOCC that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
- The definition of Control Center.
- The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

The V5TAG suggested that the Project 2016-02 SDT consider the following potential options or recommendations for resolution:

- Provide additional clarity or revisions to CIP-002-5.1a, Attachment 1. Specifically around Transmission Owner Control Centers performing the functional obligations of a Transmission Operator, in particular for entities with small or lower-risk Cyber Asset risks.
- Clarify applicability of requirements on a TOCC that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Currently, CIP-002-5.1a indicates that any Control Center performing the actions noted above is to be considered as having BES Cyber Systems categorized as medium impact, if not already identified as high impact. There is no allowance for a low-risk entity performing TOP functions to identify their assets as containing only low impact BES Cyber Systems.
- Revise the definition of Control Center if additional clarity will improve consistency in implementation, compliance and enforcement, and determination of applicability.

The TOCC whitepaper is an effort to fully inform industry about this issue and the SDT needs feedback from all industry participants on the topics in the associated comment form.

Related Issues Not in Scope of SAR

As described in the Standards Processes Manual, a SAR is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards.

Early in the SDT research effort, discussions with stakeholders revealed a potentially significant connection between the TOCC issue and the ERO Registration processes. The SDT explored this path and captured the following information.

In 2014, NERC completed development of a Risk-Based Registration process, which FERC approved in 2015. During the development effort, NERC considered the concept of a registration *lite* for those entities that may perform functional obligations but have less reliability impacts to the BES. These concerns were not specific to a registered function but were entity-dependent having a relationship with the TOCC. The Risk-Based Registration process concluded and determined there was not a defensible position for a registration *lite* concept, but given the remaining concerns, the ERO established NERC-led review panels developed from the Risk-Based Registration process to assess and confirm an impact rating for TOCCs, should the question arise in the future.

The review panel can be utilized for concerns with registration as a TO or TOP if the entity believes the designation it carries to be inappropriate. Entities that may be impacted by a change in a neighboring or fellow registered entity have a chance to participate in the panel process. To be more direct in linkage, if an entity has concerns about applicability of functional performance or tasks – this would not be addressed in a family of standards – but in the tools and programs as defined in the NERC Rules of Procedure (ROP). These are the ordered processes for any type of exception, if you will, from adherence to the standards and requirements.

In discussions with impacted stakeholders, the SDT learned that some TOPs believe they are inappropriately registered as TOPs and, as a result, are disproportionately impacted by the CIP standards. This registration issue is outside the scope of Project 2016-02. The SDT notes, however, that entities may use existing mechanisms to potentially resolve these concerns.

NERC Project 2016-02 Background

On January 21, 2016, the Commission issued Order No. 822, Revised Critical Infrastructure Protection Reliability Standards, approving seven CIP Reliability Standards and new or modified definitions. On March 9, 2016, the NERC Standards Committee (SC) authorized the SAR to be posted for a 30-day informal comment period from March 23 – April 21, 2016. Based on the comments received, the SDT made minor revisions to the SAR which was posted for an additional 30-day informal comment period June 1-30, 2016. The SC accepted the SAR revisions on July 20, 2016.

The purpose of NERC Project 2016-02 is to increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities. To help accomplish this, the SDT will: (1) address the Commission directives contained in Order No. 822, and (2) consider the V5TAG issues identified in the V5TAG Transfer Document.

It is important to note that the V5TAG issues relate to the language developed by the Project 2008-06 Cyber Security Order 706 Standards Drafting Team (706 SDT) as directed in FERC Order No. 706. The NERC Board of Trustees adopted the stakeholder-approved CIP Version 5 standards and FERC approved the standards on January 18, 2006. The Project 2016-02 SDT must consider the V5TAG issues based on the language of FERC Order No. 706 and the intent of the 706 SDT with a subset of the language captured below.

280. The Commission has two concerns regarding the misuse of facilities, and clarifies those concerns here. First, Requirement R1.2.1 requires responsible entities to consider control centers and backup control centers as potential critical assets. In determining whether those control centers should be critical assets, we believe that responsible entities should examine the impact on reliability if the control centers are unavailable, due for example to power or communications failures, or denial of service attacks. Responsible entities should also examine the impact that misuse of those control centers could have on the electric facilities they control and what the combined impact of those electric facilities could be on the reliability of the Bulk-Power System. The Commission recognizes that, when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.

FERC reiterated its position on April 19, 2012 in FERC Order No. 761 (the order approving “Version 4 Critical Infrastructure Protection Reliability Standards”):

57. The Commission recognizes the diverging views among commenters regarding the protection of control centers and control systems afforded under the Version 4 CIP Reliability Standards. In Order No. 706, we stated that “it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.” The Commission maintains this view. However, as we observed in the NOPR, the percentage of control centers to be identified as Critical Assets under Version 4 is 74 percent, which is an improvement over the number currently identified under Version 3. Therefore, it is reasonable to approve Version 4 because it will ensure that more control centers are identified as Critical Assets than are identified under Version 3. However, we continue to expect comprehensive protection of all control centers and control systems as NERC works to comply with the requirements of Order No. 706.

NERC Proposed Beta Criteria

Prior to the SAR, NERC compliance staff participating in the V5TAG recognized that Control Centers covered by the referenced criterion may not all pose the same level of risk to the BES, which is a fundamental aspect of CIP-002-5.1a impact-based categories. To evaluate each Control Center’s risk to the BES, NERC compliance staff developed beta criteria to identify Control Centers that contain medium impact BES Cyber Systems and evaluate the entity risk impact with consideration of a low impact category. The beta criteria are more fully described below.

The first beta criterion of the evaluation posed the following question: “Does the Transmission Owner’s facility operate at least two geographically separate transmission facilities?” If the answer to this beta criterion was no, the TO’s facility would be identified as an asset that contains low impact BES Cyber Systems. If the answer was yes, then the evaluation moved on to the next criterion.

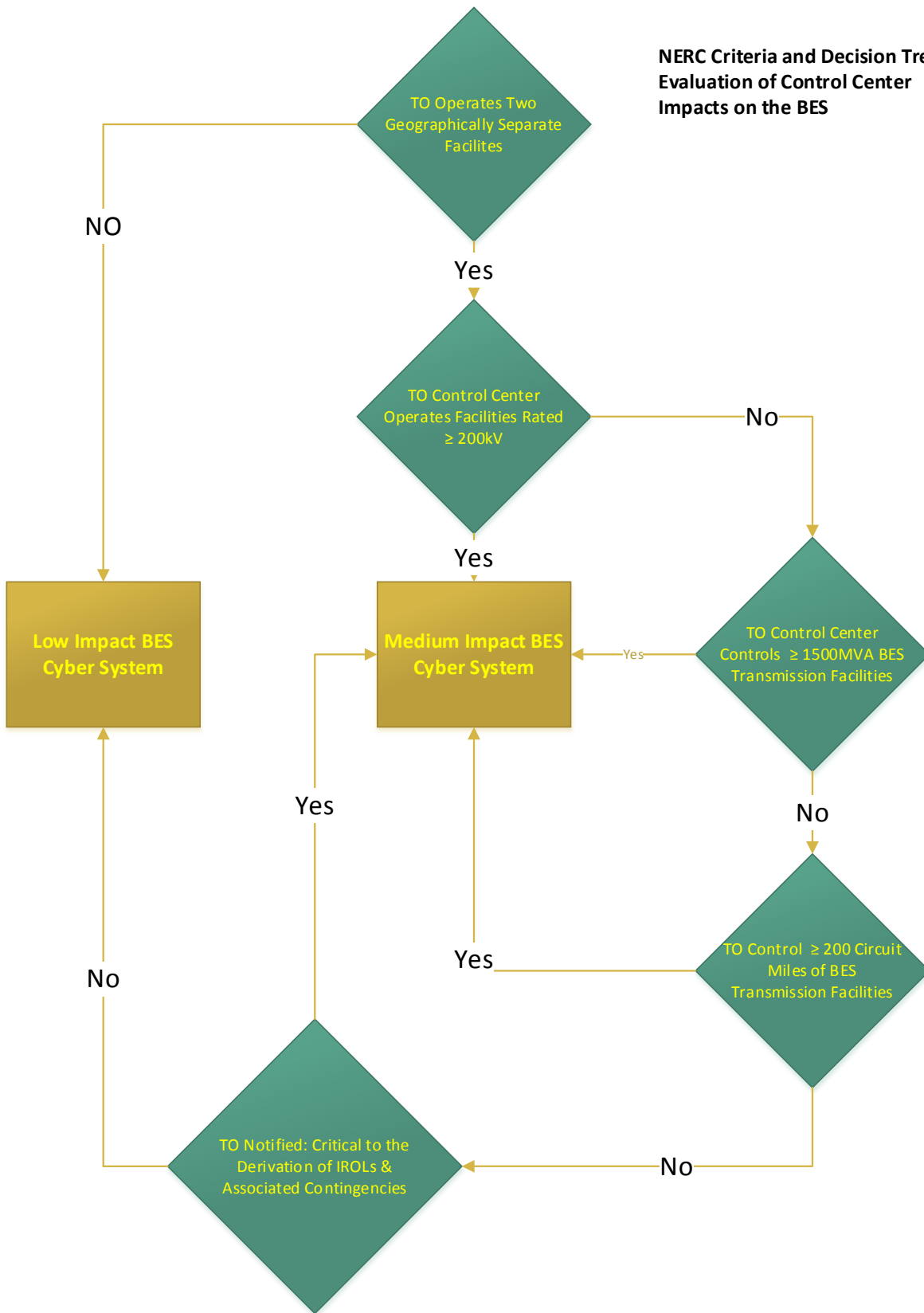
The second beta criterion consisted of the following question: “Do any of the Transmission Facilities operated by the Transmission Owner’s Control Centers operate at or greater than 200 kV?” If the answer to this question was yes, then the evaluation resulted in the Control Center being identified as an asset that contained medium impact BES Cyber System(s). If the answer to this question was no then the evaluation proceeded to the next criterion.

The third beta criterion was labeled as the Group 1 criteria and consisted of three distinct questions:

1. “Does the Transmission Owner control 1500 MVA or more of Transmission capacity at BES Transmission Facilities controlled by the Transmission Owner’s Control Centers?” It should be noted that this is not Transfer Capability through a Transmission Operator Area. Transmission capacity in this criterion was calculated by adding up the Facility ratings of all the Transmission Owner’s BES Transmission Lines and capacitor banks. If the aggregated MVA value was greater than or equal to 1500 MVA, then the Control Center was identified as an asset that contains medium impact BES Cyber System(s). If the answer to this question was no, then the evaluation moved on to the next question.
2. “Does the Transmission Owner control more than 200 miles of Transmission?” This calculation was performed by adding up all of the circuit miles of the Transmission Owner’s BES Transmission Facilities. If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s). If the answer was no then the evaluation moved on to the final question.
3. “Has the Transmission Owner been notified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as having a Facility, controlled by the Transmission Owner’s Control Centers that is critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies?” If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s), if not it was treated as an asset that contains low impact BES Cyber System(s).

The SDT continues to evaluate the beta criteria as an option to pursue. In an effort to clarify the approach as captured, the following flowchart represents the consideration path for execution of the risk assessment.

**NERC Criteria and Decision Tree:
Evaluation of Control Center
Impacts on the BES**



Performing Functional Obligations

The SDT delved further into the intent behind the language: “performing the functional obligations of” and identified the following information associated with the creation of this language. The “performing functional obligation of” language was added in CIP-002-4 by the “Project 2008-6 Cyber Security Order Phase II” Standard Drafting Team. The CIP-002-4 Identifying Critical Cyber Assets guideline document references the “functional obligation” language in terms of a “formal delegation” from the registered entity:

http://www.nerc.com/pa/Stand/CIP0024RD/Project_2008-06_CIP-002-4_Guidance_clean_20101220.pdf

The “functional obligations” language first appears in a draft of CIP-002-4. The draft guidance associated with this first introduction of the language offered the following:

Part 1.14 designates all control centers and control systems used to perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA) or Transmission Operator (TOP). EOP-008 requires that RCs, BAs and TOPs “ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.” While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets, control systems at other applicable Responsible Entities that are used to perform the functional obligations of the RCs, BAs, or TOPs must also be designated as Critical Assets. These include control systems at Transmission Owners’ control centers and backup control centers, for example, which have been formally delegated to perform some of these functions. Control systems were specifically called out separately from control centers to ensure that Entities fully evaluate those systems used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator. These control systems may be located at a data center that is not co-located with the control center itself.

As discussed in summary meeting notes from the aforementioned SDT, the SDT commented on the designation of TOCC’s as Critical Assets as follows:

“As discussed in the Reference Document, this requirement is sourced from EOP-008. Control centers performing these functional obligations are considered important enough to require mandatory backup requirements and warrant designation as Critical Assets.”

Given the information discussed above, the relationship to the operations and planning standards vary with different levels of potential impact. To perform functional tasks or obligations, a System Operator must either be certified as a Transmission Operator or Reliability Coordinator (RC) or take direction from a NERC-certified System Operator (Transmission Operator or RC). Maintaining a NERC certification can take significant investment of time and resources, so some System Operators that control BES Transmission Systems do not maintain certification and instead rely on only operating the System when directed by a NERC Certified System Operator. To address the scenario where an individual or entity is 1) performing BES Transmission operations, 2) is not a registered TOP and 3) equipment may have an impact on BES operations, the 706 SDT incorporated the language “used to perform the functional obligations of” to clarify that the equipment used by both NERC-certified System Operators and System Operators operated under the direction of a NERC-certified System Operator had to be protected and fully implement the security objective for protecting equipment used to perform TOP functions. The functional obligations of a TOP are identified in the NERC Rules of Procedure¹, with further examples included in the Functional

¹ http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20161031.pdf

Model and are also summarized in the BES Reliability Operating Services (BROS) in the Guidelines and Technical Basis of CIP-002-5.1a.

1) Capability versus Authority

In terms of CIP-002-5.1a and determination of risk level or impact classification, Attachment 1 criterion 2.12 focuses specifically on those Responsible Entities taking part in or performing both the Transmission Owner and/or the Transmission Operator reliability functions. As stated in the V5TAG Transfer Document, the language “used to perform the functional obligation of,” was intended to “capture entities that perform obligations of a specific registered function, whether they are registered for that function or not.” The statement inherently accommodates the risk that CIP-002-5.1a Attachment 1 is trying to mitigate. Regardless of how a Responsible Entity is registered, to adequately protect the BES, entities must look at not only the intended use but also the potential misuse of the BES Cyber System(s). If a malicious actor is capable of affecting the BES in a negative manner from a given BES Cyber System, that BES Cyber System needs to be protected accordingly to prevent such actions.

Regarding criterion 2.12, this notion calls into question whether it is appropriate to afford BES Cyber Systems protections based on authority to perform actions (registered functions) or capability to perform actions.

For criterion 2.12 in CIP-002-5.1a Attachment 1, it is clear that the intention is to require application of appropriate protections to BES Cyber Systems operated by Responsible Entities that fulfill TOP reliability functions, regardless of registration. An example of this would be a case where there are two Responsible Entities, one registered as a TO, and the other registered as a TOP. If the entity registered as the TO operates a Control Center and follows directives given by the TOP, the TO is clearly operating on behalf of the TOP. In this case, while the TO only does this when authorized by the TOP, the BES Cyber System(s) associated with the TO’s Control Center possess the capability to be used by an unauthorized party to affect the BES, and must be protected as a BES Cyber Asset.

2) Span of Control

The TOP’s span of control is not limited to just Transmission Lines, but to a large number of diverse Transmission Facilities that relate to the reliable operation of the BES. This complexity, together with the interrelated impact from the large number of diverse Functional Entity types that impact TOP functional obligations, makes it very difficult to define a justifiable threshold that can be rationalized considering all the scenarios that could impact Real-time operation for a TOCC.

CIP-002-5.1a, Attachment 1 categorizes BES Cyber Systems into risk based impact levels primarily based on the span of control of the BES Cyber System(s). The premise of this discussion is that the span of control for the TO and TOP functions should be more fully considered to determine whether a risk-basis exists for a low impact categorization for BES Cyber System(s) associated with Control Centers.

Evaluation of Potential Solutions

The SDT evaluated potential solutions (as recommended by V5TAG and others) against the facts and factors uncovered during the SDT research. The associated informal comment form includes questions for stakeholders that are intended to gather additional information and stakeholder positions related to these potential solutions.

1) Propose revisions to CIP-002-5.1a

If the SDT were to take action to respond to the TOCC issue, there are many variations of what may be an appropriate action. The following section proposes potential standard revision options.

a) Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12

The SDT considered the prospect of revising the Attachment 1, criterion 2.12 to add clarity for Responsible Entities. Criterion 2.12 establishes a medium impact level for “Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in high impact rating (H), above.” Under this option, the SDT would propose an impact rating criterion to establish a medium impact rating that would include a lower bound to the criterion. Control Centers with the characteristics listed below would be categorized as assets that contain medium impact BES Cyber System(s), and all others would be identified as low impact BES Cyber System(s). The impact rating criteria would be similar to the NERC proposed beta criteria referenced above. One example of a revised criterion 2.12 is as follows:

Attachment 1: criterion 2.12. Each control center or backup control center not included in the high impact rating (H) above, that is used to operate any of the following:

- Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher
- Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA
- A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
- Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path
- BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA
- Greater than 200 line miles of Transmission Lines

The SDT assessed the potential for such a revision to the criteria and found trade-offs to the proposal. This option could provide added clarity for Responsible Entities and compliance enforcement personnel in determining the assets that are in and out of scope; however, this option could still cause Control Centers with minimal risk to the BES to be identified as medium impact BES Cyber System(s). This could place significant strain on resources of minimal risk entities and the burden as well as benefit may not be commensurate to the risk of those entities.

There will be implications for both newly registered TOs as well as existing TOs. Updated criteria will trigger an analysis and implementation cycles for entities currently in scope under CIP V5 causing rework depending on what type of criteria might be considered. This is a significant consequence for entities that only recently completed implementation of CIP V5 or will still be in the process of completion of the implementation efforts. The update could likely change the impact classification of affected BES Cyber System(s). While this would be one purpose of the revision, resolution for some would be offset by new issues for others.

While the SDT is considering development of a categorization for Control Centers with a low impact rating, FERC Order No. 706 set an expectation that Control Centers would be identified as “Critical Assets,” which correspond to high and medium impact levels in the revised CIP Reliability Standards. Given the overhaul that CIP V5 represents in its expansion of scope to include all BES Cyber Systems, a lower bound for Control Centers may be justifiable.

b) Low Impact Justification Process

Another potential solution is to utilize a justification process that would provide Responsible Entities the opportunity to demonstrate that their Control Center poses a minimal risk/low impact to the BES. As contemplated, a justification process may allow the TO to perform an engineering analysis to demonstrate to the ERO Enterprise that the risk posed by its Transmission Facilities do not warrant protection of the associated BES Cyber System(s) as medium impact. The criteria upon which the ERO would assess the TO’s analysis would need to be developed. This justification process could include a review of the TO’s analysis by an unaffiliated third party.

This justification process approach could provide the clarity requested by the V5TAG and could also provide Responsible Entities a process to demonstrate its actual impact level as demonstrated by engineering studies. However, this additional process could place additional strain on limited resources for Responsible Entities and Compliance Enforcement Authorities to support the positions that certain Control Centers represent less risk or impact to the Bulk Electric System even in a situation specific to misuse or malicious threat actors.

2) No further action by the SDT

The V5TAG presented a valuable opportunity for NERC, the Regions and industry to consider the CIP V5 language under implementation and consider areas that may benefit from added clarity. However, the SDT evaluation must take into account the breadth and diversity of the entities to which the CIP V5 language applies. The language under evaluation by the SDT relative to the TOCC issues raised by the V5TAG was approved by NERC stakeholders through an open and transparent process. The current state reflects that FERC approved language is in effect and currently no direction to modify the language has been given.

In addition, CIP V5 only became mandatory and enforceable on July 1, 2016. Familiarity with the full implications and effectiveness of the standards is still new and untested.

From research and analysis, the option to take no further action could potentially be based on the following reasons:

- The TOCC situation represents individualized company positions and each entity must be evaluated for risk and impact suggesting a widely applicable standard is not appropriate to represent a norm or majority.
- The currently approved language maintains the intent of the CIP V5 language.
- Revision of the Control Center definition is not needed to resolve this issue and has broader implications that are not limited to this project.
- Standards development should not be utilized to solve potential concern about compliance monitoring or enforcement. Alternative ERO tools exist such as the BES Exception Process and NERC led review panels related to Risk Based Registration Processes should be pursued to resolve entity concerns before revising the approved and implemented standard language. If there is validity or need to open the standards for revision, the SDT is asking for this specific feedback.

The SDT understands that, absent an action not proposed within this TOCC White Paper, a decision to take no further action on the TOCC issue area confirms the existing criteria in CIP-002-5.1a Attachment 1, including criterion 2.12 which identifies all BES Cyber System(s) associated with TOCCs performing the functional obligations of a TOP as medium impact.

Next Steps

The SDT requests industry stakeholders consider the discussion and options detailed above and provide informal comments to the SDT. Input to the comment form questions will help confirm the influential facts and circumstances around this issue and aid the SDT in determining recommended actions.

Exhibit G

Project 2016-02
Standard Drafting Team Roster

Standard Drafting Team Roster

Project 2016-02 Modifications to CIP Standards

	Name	Entity
Co-Chair	Jay Cribb	Southern Company
Co-Chair	Matthew Hyatt	Tennessee Valley Authority
Members	Jake Brown	ERCOT
	Norman Dang	Independent Electricity System Operator of Ontario
	Robert Garcia	Southwest Power Pool, Inc.
	Scott Klauminzer	Tacoma Public Utilities, Tacoma Power
	Sharon Koller	American Transmission Company, LLC
	Forrest Krigbaum	Bonneville Power Administration
	Heather Morgan	EDP Renewables
	Mark Riley	AECI
	Robert Thompson	North Carolina Electric Membership Corp
PMOS Liaisons	Ken Lanehome	Bonneville Power Administration
	Kirk Rosener	CPS Energy
NERC Staff	Jordan Mallory – Standards Developer	North American Electric Reliability Corporation
	Shamai Elstein – Senior Counsel	North American Electric Reliability Corporation
	Marisa Hecht – Counsel	North American Electric Reliability Corporation