Exhibit A

Implementation Plans for CIP-002-2 through CIP-009-2 and
CIP-002-3 and CIP-009-3
For Generator Owners and Generator Operators of
U.S. Nuclear Power Plants

Proposed Clean and Redline for Version 2 Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised Implementation Plan for Version 2 of Cyber Security Standards CIP-002-2 through CIP-009-2
January 20, 2010

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Modified Standards
The following standards have been modified:
CIP–002–2 — Cyber Security — Critical Cyber Asset Identification
CIP–003–2 — Cyber Security — Security Management Controls
CIP–004–2 — Cyber Security — Personnel and Training
CIP–005–2 — Cyber Security — Electronic Security Perimeter(s)
CIP–006–2 — Cyber Security — Physical Security
CIP–007–2 — Cyber Security — Systems Security Management
CIP–008–2 — Cyber Security — Incident Reporting and Response Planning
CIP–009–2 — Cyber Security — Recovery Plans for Critical Cyber Assets

Red-line versions of the above standards are posted with this Implementation Plan. When these modified standards become effective, the prior versions of these standards and their Implementation Plan are retired.

Compliance with Standards
Once these standards become effective, the responsible entities identified in the Applicability section of the standard must comply with the requirements. These include:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

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Newly registered entities must comply with the requirements of CIP-002-2 through CIP-009-2 within 24 months of registration. The sole exception is CIP-003-2 R2 where the newly registered entity must comply within 12 months of registration.

Proposed Effective Date

The proposed effective date for these modified standards is the first day of the third calendar quarter (i.e., a minimum of two full calendar quarters, and not more than three calendar quarters) after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

For example, if regulatory approval is granted in June, the standards would become effective January 1 of the following year. If regulatory approval is granted in July, the standards would become effective April 1 of the following year.

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010[1] and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps

[1] These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

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RELIABILITY CORPORATION

Revised Implementation Plan for Version 2 of Cyber Security Standards CIP-002-2 through CIP-009-2
January 20, 2010

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Modified Standards
The following standards have been modified:
CIP–002–2 — Cyber Security — Critical Cyber Asset Identification
CIP–003–2 — Cyber Security — Security Management Controls
CIP–004–2 — Cyber Security — Personnel and Training
CIP–005–2 — Cyber Security — Electronic Security Perimeter(s)
CIP–006–2 — Cyber Security — Physical Security
CIP–007–2 — Cyber Security — Systems Security Management
CIP–008–2 — Cyber Security — Incident Reporting and Response Planning
CIP–009–2 — Cyber Security — Recovery Plans for Critical Cyber Assets

Red-line versions of the above standards are posted with this Implementation Plan. When these modified standards become effective, the prior versions of these standards and their Implementation Plan are retired.

Compliance with Standards
Once these standards become effective, the responsible entities identified in the Applicability section of the standard must comply with the requirements. These include:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

Newly registered entities must comply with the requirements of CIP-002-2 through CIP-009-2 within 24 months of registration. The sole exception is CIP-003-2 R2 where the newly registered entity must comply within 12 months of registration.

Proposed Effective Date

The proposed effective date for these modified standards is the first day of the third calendar quarter (i.e., a minimum of two full calendar quarters, and not more than three calendar quarters) after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

For example, if regulatory approval is granted in June, the standards would become effective January 1 of the following year. If regulatory approval is granted in July, the standards would become effective April 1 of the following year.

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010[1] and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on

[1] These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

Proposed Clean and Redline for Version 3 Implementation Plan

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Revised Implementation Plan for Version 3 of Cyber Security Standards CIP-002-3 through CIP-009-3
January 20, 2010

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Applicable Standards

The following standards are covered by this Implementation Plan:

CIP–002–3 — Cyber Security — Critical Cyber Asset Identification
CIP–003–3 — Cyber Security — Security Management Controls
CIP–004–3 — Cyber Security — Personnel and Training
CIP–005–3 — Cyber Security — Electronic Security Perimeter(s)
CIP–006–3 — Cyber Security — Physical Security
CIP–007–3 — Cyber Security — Systems Security Management
CIP–008–3 — Cyber Security — Incident Reporting and Response Planning
CIP–009–3 — Cyber Security — Recovery Plans for Critical Cyber Assets

These standards are posted for ballot by NERC together with this Implementation Plan. When these standards become effective, all prior versions of these standards are retired.

Compliance with Standards

Once these standards become effective, the Responsible Entities identified in the Applicability section of the standard must comply with the requirements. These Responsible Entities include:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

Proposed Effective Date

The Responsible Entities shall be compliant with all requirements on the Effective Date specified in each standard.

Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities

Concurrently submitted with Version 3 of Cyber Security Standards CIP-002-3 through CIP-009-3 is a separate Implementation Plan document that would be used by the Responsible Entities to bring any newly identified Critical Cyber Assets into compliance with the Cyber Security Standards, as those assets are identified. This Implementation plan closes the compliance gap created in the Version 1 Implementation Plan whereby Responsible Entities were required to annually determine their list of Critical Cyber Assets, yet the implication from the Version 1 Implementation Plan was that any newly identified Critical Cyber Assets were to be immediately 'Auditably Compliant', thereby not allowing Responsible Entities the necessary time to achieve the Auditably Compliant state.

The Implementation Plan for newly identified Critical Cyber Assets provides a reasonable schedule for the Responsible Entity to achieve the 'Compliant' state for those newly identified Critical Cyber Assets.

The Implementation Plan for newly identified Critical Cyber Assets also addresses how to achieve the 'Compliant' state for: 1) Responsible Entities that merge with or are acquired by other Responsible Entities; and 2) Responsible Entities that register in the NERC Compliance Registry during or following the completion of the Implementation Plan for Version 3 of the NERC Cyber Security Standards CIP-002-3 to CIP-009-3.

Prior Version Implementation Plan Retirement

By December 31, 2009, CIP Version 1's Table 1, 2, and 3 Registered Entities that registered prior to December 31, 2007 will have reached the "Compliant" milestone for all CIP Version 1 Requirements. Timetables for reaching the "Auditably Compliant" milestone will still be in effect for these Entities going forward until said timetables expire. As such, when Table 3 Registered Entities reach the Auditably Compliant milestone on December 31, 2010, the Version 1 Implementation Plan is in practice retired. Table 4 of the CIP Version 1 Implementation Plan is applicable only for newly Registered Entities, and compliance milestones for newly Registered Entities is included in CIP Version 2's Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities effective on April 1, 2010. CIP Version 3 milestones, are effective after FERC approval.

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010[1] and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

[1] These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Revised Implementation Plan for Version 3 of Cyber Security Standards CIP-002-3 through CIP-009-3
January 20, 2010

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Applicable Standards
The following standards are covered by this Implementation Plan:

CIP–002–3 — Cyber Security — Critical Cyber Asset Identification
CIP–003–3 — Cyber Security — Security Management Controls
CIP–004–3 — Cyber Security — Personnel and Training
CIP–005–3 — Cyber Security — Electronic Security Perimeter(s)
CIP–006–3 — Cyber Security — Physical Security
CIP–007–3 — Cyber Security — Systems Security Management
CIP–008–3 — Cyber Security — Incident Reporting and Response Planning
CIP–009–3 — Cyber Security — Recovery Plans for Critical Cyber Assets

These standards are posted for ballot by NERC together with this Implementation Plan. When these standards become effective, all prior versions of these standards are retired.

Compliance with Standards
Once these standards become effective, the Responsible Entities identified in the Applicability section of the standard must comply with the requirements. These Responsible Entities include:

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Service Provider
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Load Serving Entity
- NERC
- Regional Entity

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Proposed Effective Date

The Responsible Entities shall be compliant with all requirements on the Effective Date specified in each standard.

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Concurrently submitted with Version 3 of Cyber Security Standards CIP-002-3 through CIP-009-3 is a separate Implementation Plan document that would be used by the Responsible Entities to bring any newly identified Critical Cyber Assets into compliance with the Cyber Security Standards, as those assets are identified. This Implementation plan closes the compliance gap created in the Version 1 Implementation Plan whereby Responsible Entities were required to annually determine their list of Critical Cyber Assets, yet the implication from the Version 1 Implementation Plan was that any newly identified Critical Cyber Assets were to be immediately 'Auditably Compliant', thereby not allowing Responsible Entities the necessary time to achieve the Auditably Compliant state.

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The Implementation Plan for newly identified Critical Cyber Assets also addresses how to achieve the 'Compliant' state for: 1) Responsible Entities that merge with or are acquired by other Responsible Entities; and 2) Responsible Entities that register in the NERC Compliance Registry during or following the completion of the Implementation Plan for Version 3 of the NERC Cyber Security Standards CIP-002-3 to CIP-009-3.

Prior Version Implementation Plan Retirement

By December 31, 2009, CIP Version 1's Table 1, 2, and 3 Registered Entities that registered prior to December 31, 2007 will have reached the "Compliant" milestone for all CIP Version 1 Requirements. Timetables for reaching the "Auditably Compliant" milestone will still be in effect for these Entities going forward until said timetables expire. As such, when Table 3 Registered Entities reach the Auditably Compliant milestone on December 31, 2010, the Version 1 Implementation Plan is in practice retired. Table 4 of the CIP Version 1 Implementation Plan is applicable only for newly Registered Entities, and compliance milestones for newly Registered Entities is included in CIP Version 2's Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities effective on April 1, 2010. CIP Version 3 milestones, are effective after FERC approval.

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010[1] and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

[1] These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

Exhibit B

Record of Development of Proposed Implementation Plans

Standards Announcement

Ballot Pool and Pre-ballot Window (with Comment Period)
July 20–August 14, 2009

Ballot Pool: https://standards.nerc.net/BallotPool.aspx

Comments:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Cyber Security — Order 706B Nuclear Plant Implementation Plan

A draft implementation plan for Version 1 critical infrastructure protection (CIP) Reliability Standards CIP-002-1 through CIP-009-1 for Nuclear Power Plants has been posted for a simultaneous pre-ballot review and comment period.

In order to be responsive to the September 15, 2009 filing deadline and as a reflection of the significant involvement of the nuclear community in the development of this proposal, the NERC Standards Committee approved the team to shorten the comment period and hold the comment period at the same time as the pre-ballot review period, and if necessary, offer changes to the proposal based on the comments received before proceeding to ballot.

Ballot Pool

Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on August 14, 2009**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-Order706B_ImpPlan_in.

Comments

An associated comment period is open **until 8 a.m. EDT on August 14, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Project Background:

On January 18, 2008, FERC (or "Commission") issued Order No. 706 that approved Version 1 of the CIP Reliability Standards: CIP-002-1 through CIP-009-1. On March 19, 2009, the Commission issued clarifying Order No. 706-B that clarified "the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory "CIP" Reliability Standards approved in Commission Order No. 706." However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, the Commission noted in ¶59 that,

> "[i]t is not appropriate to dictate the schedule contained in Table 3 of NERC's Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.
>
> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants' full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule."

This project addresses the development of the implementation plan specific for nuclear power plants. The draft plan was drafted by members of the original Version 1 Cyber Security Drafting Team with specific outreach to nuclear power plant owners and operators to ensure their interests were fairly represented. Further background information is available in the posted comment form.

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Unofficial Comment Form for the Draft Implementation Plan for Version 1 of the CIP Reliability Standards

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the draft Implementation Plan for Version 1 Critical Infrastructure Protection Reliability Standards — CIP-002-1 through CIP-009-1 for Nuclear Power Plants. The electronic comment form must be completed by **August 14, 2009.** In order to be responsive to the September 15, 2009 filing deadline and as a reflection of the significant involvement of the nuclear community in the development of this proposal, the NERC Standards Committee approved the team to shorten the comment period and pre-ballot review period, and if necessary, offer changes to the proposal based on the comments received before proceeding to ballot.

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

If you have questions please contact Gerry Adamski at gerry.adamski@nerc.net or by telephone at 609-524-0617.

Background Information

On January 18, 2008, FERC (or “Commission”) issued Order No. 706 that approved Version 1 of the Critical Infrastructure Protection Reliability Standards, CIP-002-1 through CIP-009-1. On March 19, 2009, the Commission issued clarifying Order No. 706-B that clarified “that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory “CIP” Reliability Standards approved in Commission Order No. 706.” However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, the Commission noted in ¶59 that,

> “[i]t is not appropriate to dictate the schedule contained in Table 3 of NERC’s Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.
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> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants’ full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule.”

As a standard’s implementation plan is a required element per the Reliability Standards Development Procedure, any new or revised plan must proceed through the stakeholder development process. Thus, many members of the original Version 1 Cyber Security Drafting Team agreed to participate in the development of the implementation plan specific for nuclear power plants, with specific outreach to nuclear power plant owners and operators, to ensure their interests were fairly represented and considered in the proposed implementation plan that is the subject of this comment period.

In its consideration, the team contemplated the use of the updated implementation plan that was produced to accompany Version 2 of the CIP standards recently approved by the NERC Board as a starting point for the discussion. The team also recognized in its deliberation that certain of the CIP requirements may require a unit outage to implement. In the end, the team agreed that the approach presented reflects a reasonable schedule for implementation by the US nuclear power plants that acknowledges that cyber security initiatives have been underway within the nuclear industry for several years as instituted by the Nuclear Regulatory Commission and the Nuclear Energy Institute, the nuclear industry's organization for establishing unified policy on matters affecting its constituency.

As background to this last point, in 2004, the nuclear industry completed development of NEI-04-04 that facilitated the establishment of a comprehensive cyber security program for all digital assets at a nuclear plant site. Endorsed by the NRC in late 2005, the program was implemented by all sites in May, 2008. Development work on an updated program began in 2008, titled NEI-08-09, that is intended to assist nuclear plants in complying with newly established NRC regulation 10 CFR 73.54, issued in March, 2009. All nuclear plants are required to submit a detailed cyber security plan and implementation schedule to the NRC by November 23, 2009 as part of the regulation. In addition, as part of the evaluation of FERC's proposed order of clarification that led to Order No. 706-B, the nuclear industry performed an analysis of the NEI-04-04 program and the NERC CIP standards and identified few differences.

Given this context, the drafting team developed the proposed implementation schedule that it believes is an appropriate timeline for compliance by all US nuclear power plants. The timelines described are predicated upon three key aspects:

1. FERC must approve the implementation plan for it to take effect. This FERC approval date is referenced in the table's "Timeframe to Compliance" column by the label "R".
2. The specific systems, structures, and components must be identified regarding the regulatory jurisdiction in which it resides in order to determine whether NERC CIP standards must be applied. This scope of systems determination, reflected by the label "S" in the table's "Timeframe to Compliance" column, includes the completion of an executed Memorandum of Understanding between NERC and the NRC on this and other related issues. The scope of system determination also requires the establishment of the exemption process for excluding certain systems, structures, and components from the scope of NERC CIP standards as provided for in Order 706-B.
3. Certain of the NERC CIP standards can only be implemented with the unit off-line. Therefore, certain requirements are likely outage-dependent and are so identified by the label "RO" in the table's "Timeframe to Compliance" column. These items need to be included in the plant's "checkbook" indicating they are planned and budgeted for as part of the planned outage activities. In this context, the refueling outage refers to the first refueling outage at least 12 months beyond the FERC approval date to provide the time needed to plan and budget the activities.

   Specifically, aspects of CIP-005-1, CIP-007-1, and CIP-008-1 requirements pertaining to the **development** of plans, processes, and protocols shall be completed the later of R+18 or S+10. For aspects of requirements that implement the plans, processes, and protocols (and related documentation requirements regarding that implementation), the Responsible Entity shall **perform the implementation** the later of R+18 or S+10 or RO+6 if an outage is required to implement the plans, processes, and protocols. The Responsible Entity will be expected to assess whether a refueling outage is needed during the initial self-certification process for the CIP Version 1 standards for nuclear power plants and provide the information in its self-certification report. For multi-unit nuclear power plants, should separate outages be required to implement the plans, processes, ands protocols for all units at the plant, the Responsible Entity shall indicate the need for separate outages in its self-certification report, including the time frame needed for implementation for each unit.

Each of these factors can become the critical path item that determines an appropriate timeline for compliance; therefore, the proposed implementation plan is structured so that the timeline for compliance becomes the later of:

- the FERC approval date plus an appropriate number of months;
- the scope of systems determination plus an appropriate number of months; or,
- the refueling outage (if applicable) plus an appropriate number of months (to enable the implementation of certain actions during the outage and the completion of the documentation requirements for the implemented changes thereafter)

In summary, the team is seeking industry input to the proposed implementation plan through the following series of questions. Please note that proposed implementation timeframes are provided only at the main requirement level and all components of the main requirement are therefore intended for inclusion in the timeline.

1. Does the *structure* of the timeframe for compliance represent a reasonable approach that acknowledges the critical path items that could impact implementation of the CIP requirements?

   Comments:

2. Does the proposed implementation plan generally provide a reasonable timeframe for implementing NERC's CIP Version 1 standards at nuclear power plants?

   Comments:

3. Are there any requirements in CIP-002-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States?

   Comments:

4. Are there any requirements in CIP-003-1, CIP-004-1, CIP-006-1, and CIP-009-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States? Implementation of these standards is not believed to be predicated on an outage.

   Comments:

5. Are there any requirements in CIP-005-1, CIP-007-1, and CIP-008-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the

nuclear power plants in the United States? Implementation of certain aspects of these standards is believed to be predicated on an outage.

Comments:

Individual or group. (15 Responses)
Name (8 Responses)
Organization (8 Responses)
Group Name (7 Responses)
Lead Contact (7 Responses)
Question 1 Comments (15 Responses)
Question 2 Comments (15 Responses)
Question 3 Comments (15 Responses)
Question 4 Comments (15 Responses)
Question 5 Comments (15 Responses)

Group
Exelon Generation Company, LLC - Exelon Nuclear
Alison Mackellar
The structure of the timeframe for compliance presents a generally reasonable approach; however, given that the nuclear industry has not yet performed an assessment in accordance with CIP-002 (R.2, R.3) the scope is difficult to determine.
The proposed implementation plan generally provides a reasonable timeframe for implementing NERC's CIP Version 1 except as noted in the response to other questions, below. In addition, it is our understanding that "Auditably Compliant" will be required one year following the compliance milestone defined in the implementation plan. "Auditably Compliant" means the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable "data," "documents," "documentation," "logs," and "records."
The proposed time frame is suitable for implementation; however, the execution of the identification of a critical asset and identification of critical cyber assets will present a challenge especially during the later milestones that include final review and signoff from senior executives.
For CIP-003-1, CIP-006-1, and CIP-009-1, No. For CIP-004-1, the proposed time frame is reasonable; however, depending on the identified personnel within scope, completion of the training program (R.2) may be a challenge to have completed by the later of the R+18 or S+10 timeframes.
No. The time frames for the requirements in CIP-005-1, CIP-007-1, and CIP-008-1 are suitable for implementation.
Group
Southern Company

Hugh Francis
Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the “S – Scope of Systems Determination” timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. Southern Company would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
With the exception of the above comment, concerning the “S” timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: “RO=Next refueling outage beyond 18 months of FERC Effective Date”
With the exception of the comment to question 1 the time frames are suitable.
With the exception of the comment to question 1 the time frames are suitable. While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage

Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details. While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Individual
Doug Engraf
Black & Veatch - Consulting Engineers
We are concerned the time frame between the plant determining the SSCs that are subject to FERC jurisdiction with Memo of Understanding between NERC and NRC and the time to acceptance of that memo. In other words, we are concerned that NERC or the NRC might not accept the SSCs as submitted and the plant's work plan may need significant changes. We would like to see the time to completion tied to acceptance of the SSC list by the NRC and NERC.
The time frame is acceptable as long as long as it is tied to the agreement on which SSCs require NERC CIP compliance.
should not be a problem
With regard to CIP-009-1, deployment of some types of backup and restore systems (including development of complete system backups of CCA's), might be best performed during an outage to prevent impact traffic to ESP network.
Refer to response to Question #1 - If the timeframe is not tied to the NRC and NERC acceptance of the SSC list, the schedule for deployement of the required network security systems, including potential upgrades to existing systems, may be of concern.
Group
PPL Supply Group
Annette Bannon
The structure of the timeframe is reasonable. It reflects the critical path items for the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. The "S" designation is not clear that it includes time to file for an exemption. PPL would like to ensure that the S timeframe allow time for the entity to review the requirements, file for an exemption, and receive a response on the outcome before the S timeclock starts.
PPL does not feel the timeframe allowed for outage activities will provide enough time for identifying solutions, planning, and implementing the requirements. The order of compliance within 12 months is too short considering once each unit is identified as a critical asset, the critical asset changes budgeted and designed, and then planning and

implementing the changes via the work management system. The current implementation schedule is determined as the latter of R+18, S+10, or RO+6. This becomes apparent when an outage would begin 13-14 months after FERC approval. This would require a plant to be compliant in 19-20 months. When we add up all of the design, plan, implement timeframes utilizing our process this would take 24 months...in this case we would have to be compliant in 7-10 months. Therefore the definition of RO needs to change to next refueling outage beyond 18 months of the FERC effective date.
With the exception of the comment to question 1, the time frames are acceptable.
With the exception of the comment to question 1, the time frames are acceptable.
With the exception of the items that require an outage to implement, the timeframes are acceptable. For the items that require an outage to perform, the timeframes are not acceptable, see answer to question 2 above. Consideration needs to be given in these CIPs for the possibility of having to fully implement them in an outage and depends upon the strategy implemented under CIP-005-1.
Individual
Janardan Amin
Luminant Power- CPNPP
Yes, the structure represents a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the associated timeframes. While the definition of the “S – Scope of Systems Determination” timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. Luminant Power would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
With the exception of the above comment, concerning the “S” timeframe, the items that do not require a refueling outage to implement, the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and

documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: “RO=Next refueling outage beyond 18 months of FERC Effective Date”
With the exception of the comment to question 1 the time frames are suitable.
For CIP-003-1, CIP-004-1: With the exception of the comment to question 1 the time frames are suitable. For CIP-006-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process For CIP-009-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
For CIP-005-1:The time frames allowed for implementing these requirements are not suitable. See answer to question 2 above for details. For CIP-007-1 & CIP-008-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details.
Individual
Marcus Lotto - on behalf of SCE’s subject matter experts
Southern California Edison Company
Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the “S – Scope of Systems Determination” timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. Southern California Edison would

like to ensure the “S” time frame allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts? One other item that should be taken into consideration is that the proposed timeline identified in the implementation plan is contingent, in part, on the development of the Memorandum of Understanding (MOU) between NERC and NRC. Because the MOU is intended to address both the "exception process" and audit responsibilities, SCE is concerned with the lack of transparency in MOU development. SCE believes stakeholders would have valuable input into the MOU development, input that would ultimately benefit the industry. Therefore, SCE strongly recommends the MOU development include direct stakeholder participation, or at minimum, solicitation of stakeholder comment prior to adoption.
With the exception of the above comment, concerning the “S” timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: “RO=Next refueling outage beyond 18 months of FERC Effective Date”
With the exception of the comment to question 1, the time frames are suitable.
With the exception of the comment to question 1 the time frames are suitable. While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005, then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be

labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details. While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance, R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005, then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Group
Electric Market Policy
Jalal Babik
The structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is adequate, there are a few clarifications that need to be made to the structure. While the definition of the “S – Scope of Stems Determination” timeframe includes a statement that the exemption process is included, it is not clear if it includes time to file for the exemption. Dominion would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
With the exception of the above comment, concerning the “S” timeframe, the timeframes are reasonable for implementing CIP requirements for the items that do not require a refueling outage to implement. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements, each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activitiy is required 12 months after the FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included in the next refueling outage. With the current implementation schedule, each unit would be required to be compliant the latter of R+18, S+10 or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget, we would first need to develop a design change. A design change of this type would take a minimum of 6

months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant, then the total time required would be 24 months. In this scenario, the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget and implement the required design changes, the definition of RO should be: “RO=Next refueling outage beyond 18 months of FERC effective date.”
With the exception of the comment to Question 1, the time frames are suitable.
With the exception of the comment to Question 1, the time frames are suitable. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
With the exception of the items that require an outage to perform, the time frames are not acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See response to Question 2 above for details. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
Group
Northeast Power Coordinating Council
Guy Zito
The structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is adequate, there are a few clarifications that need to be made to it. While the definition of the “S – Scope of Stems Determination” timeframe includes a statement that the exemption process is included, it is not clear if it includes time to file for the exemption. It should be ensured that the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
With the exception of the above comment concerning the “S”

timeframe, the timeframes are reasonable for implementing CIP requirements for the items that do not require a refueling outage to implement. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements, each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activitiy is required 12 months after the FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included in the next refueling outage. With the current implementation schedule, each unit would be required to be compliant the latter of R+18, S+10 or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant, then the total time required would be 24 months. In this scenario, the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget and implement the required design changes, the definition of RO should be: “RO=Next refueling outage beyond 18 months of FERC effective date.”
With the exception of the comment to Question 1, the timeframes are suitable.
With the exception of the comment to Question 1, the timeframes are suitable. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance, R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
With the exception of the items that require an outage to perform, the time frames are not acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See response to Question 2 above for details. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess

the need for an outage to satisfy these requirements and report that during the self-certification process.
Individual
James Starling
SCE&G
Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the "S – Scope of Systems Determination" timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. South Carolina Electric & Gas would like to ensure the "S" timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the "S" time clock starts. Is the "S" timeframe intended to allow for the exemption process to be complete before the clock starts?
With the exception of the previous comment, concerning the "S" timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements the unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once the unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: "RO=Next refueling outage beyond 18 months of FERC Effective Date"
With the exception of the comment to question 1 the time frames are suitable.
CIP-003-1: With the exception of the comment to question 1 the time frames are suitable. CIP-004-1: With the exception of the comment to

question 1 the time frames are suitable. CIP-006-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement cannot be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process. CIP-009-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement cannot be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
CIP-005-1: The time frames allowed for implementing these requirements are not suitable. See answer to question 2 above for details. CIP-007-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details. CIP-008-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details.
Individual
Benjamin Church
NextEra Energy Resources, LLC
Yes, in general the basic structure provides a foundation to establish the correct schedule to implement the reliability standards. One area of concern is in the detail of "S - Scope of Systems Determination" date. There is uncertainty as to whether the MOU between NERC and the NRC will include a matrix or other methodology that will clearly define standard plant systems assigned to NERC or the NRC (i.e., identify the “bright line”). Determination of the "bright line" can also be accomplished by including a period for nuclear plants to evaluate the exemption process, file for exemptions, and receive rulings on filed exemptions. This approach should allow adequate time completion of the exception process before declaring the "S" date.
The prerequisite approvals or activities do not allow for adequate time to implement a compliant program as follows: 1) Nuclear plants will need 12 months to identify assets and any mitigation items that will be required for compliance to CIP-002. Also, there may be plant design changes required in support of the program requirements. Industry standard "fast track" design changes take 9 months to complete which includes completing the detailed design and establishing complete configuration documentation. Implementation of the engineering design takes an additional 3 months to prepare instructions and complete the work which must be coordinated within the plant work management process. This requires R+24 to perform implementation. 2) Comments from question 1 above identifies the adjustment to "S". 3) Design

changes that require a refueling outage impact generation or the safe operation of the plant. Refueling Outages are budgeted, engineered, and planned with longer lead times due to the complexity of work activities. The proposed implementation plan will require some facilities to execute design change packages without adequate time to meet the refueling planning window of 24 months. Adding the 24 months for the refueling design and planning window implementation to the previously stated 12 months for the completion of CIP-002 requires a refueling outage 36 months from the effective date. Some plants have longer fuel cycles so it is recommended the RO effective date is "First refueling outage beyond R +18 month+ one fuel cycle".
See comments from question 1 and 2 above for time frame comments. Implementation of the CIP standards on some Balance of Plant systems is focused on regulatory compliance and the alignment of processes. Due to compliance with NEI 04-04, the industry has implemented cyber security barriers that protect generation and there is no cyber security or reliability gap.
See comments from question 1 and 2 above for time frame comments. Until detailed assessments are completed, it is generally unknown if there are items that can not be installed without a design change during a refueling outage to fully meet all requirements in CIP R03,R04, R06, and R09. The plant should be able to assess the need for a refueling outage to completely satisfy the requirements and provide final reporting during the self certification process. See comments from question 3 above for comments on no reliability gap.
See comments from question 1 and 2 above for time frame comments. See comments from question 3 above for comments on no reliability gap.
Group
Generator Operator
Silvia Parada-Mitchell
Yes, in general the basic structure provides a foundation to establish the correct schedule to implement the reliability standards. One area of concern is in the detail of "S - Scope of Systems Determination" date. There is uncertainty as to whether the MOU between NERC and the NRC will include a matrix or other methodology that will clearly define standard plant systems assigned to NERC or the NRC (i.e., identify the “bright line”). Determination of the "bright line" can also be accomplished by including a period for nuclear plants to evaluate the exemption process, file for exemptions, and receive rulings on filed exemptions. This approach should allow adequate time completion of the exception process before declaring the "S" date.
The prerequisite approvals or activities do not allow for adequate time to implement a compliant program as follows: 1) Nuclear plants will need 12 months to identify assets and any mitigation items that will be required for compliance to CIP-002. Also, there may be plant design changes required in support of the program requirements. Industry standard "fast track" design changes take 9 months to complete which includes completing the detailed design and establishing complete configuration documentation. Implementation of the engineering design takes an additional 3 months to prepare instructions and complete the work which must be coordinated within the plant work management process. This requires R+24 to perform implementation. 2) Comments from question 1 above identifies the adjustment to "S". 3) Design changes that require a refueling outage impact generation or the safe operation of the plant. Refueling Outages are budgeted, engineered, and

planned with longer lead times due to the complexity of work activities. The proposed implementation plan will require some facilities to execute design change packages without adequate time to meet the refueling planning window of 24 months. Adding the 24 months for the refueling design and planning window implementation to the previously stated 12 months for the completion of CIP-002 requires a refueling outage 36 months from the effective date. Some plants have longer fuel cycles so it is recommended the RO effective date is "First refueling outage beyond R +18 month+ one fuel cycle".
See comments from question 1 and 2 above for time frame comments. Implementation of the CIP standards on some Balance of Plant systems is focused on regulatory compliance and the alignment of processes. Due to compliance with NEI 04-04, the industry has implemented cyber security barriers that protect generation and there is no cyber security or reliability gap.
See comments from question 1 and 2 above for time frame comments. Until detailed assessments are completed, it is generally unknown if there are items that can not be installed without a design change during a refueling outage to fully meet all requirements in CIP R03,R04, R06, and R09. The plant should be able to assess the need for a refueling outage to completely satisfy the requirements and provide final reporting during the self certification process. See comments from question 3 above for comments on no reliability gap.
See comments from question 1 and 2 above for time frame comments. See comments from question 3 above for comments on no reliability gap.
Individual
Greg Rowland
Duke Energy
Overall, the structure represents a reasonable approach. However, as described in the implementation plan, the “S” (Scope of Systems Determination) seems to include only completion of the NERC/NRC MOU and establishment of the exemption process. 10 months following “S” is barely adequate time for an entity to review the Scope of Systems Determination, identify exemptions and seek NERC approval of the exemptions. NERC will then need time to process exemption requests. NERC’s denial of an exemption should be the event which starts the clock on the “S+10” month timeframe for compliance. That point of denial by NERC would place the item “in scope” and the clock for implementation of CIP standards for that item would start. “S+10” would mean that 10 months after denial of the exemption by NERC you would have to be in compliance. Also, defining “RO” as the first refueling outage 12 months after the FERC effective date does not allow adequate time to design, develop, budget, plan and implement modifications requiring a refueling outage, since some utilities are on a 24-month refueling cycle. “RO” should be defined as the first refueling outage greater than 24 months after the FERC effective date. However, in cases where exemptions are sought for items that require a refueling outage and are subsequently denied by NERC, “RO” should be the first refueling outage greater than 24 months after the denial of the exemption by NERC.
Timeframes are suitable, except for our concern as noted in response to Question #1 above.
Timeframes are suitable, except for our concern as noted in response to Question #1 above.
The implementation plan for CIP-006-1 requirements doesn’t include

any “RO+6” timeframes. Depending upon how the physical security plan is implemented, some elements of it might require a refueling outage. Otherwise, timeframes are suitable, except for our concern as noted in response to Question #1 above.
In addition to our concern noted in response to Question #1 above, we have a concern with Requirement R3 of CIP-007-1 which requires installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s). There are many cyber security system devices such as relays and programmable logic controllers which cannot accept software patches. NERC’s technical feasibility exception process doesn’t currently allow an exemption for Requirement R3. If such devices will be required to meet R3, then the timeframe for compliance would be significantly longer than “RO+6”. In some cases, CIP-compliant replacement equipment may not even be available for nuclear-grade applications, and we could NEVER achieve compliance. Similarly, Requirement R5.3.2 requires that passwords shall consist of a combination of alpha, numeric, and “special” characters. Commonly used tools, including Active Directory can enforce password parameters such the following: The password contains characters from at least three of the following five categories: (i) English uppercase characters (A - Z); (ii) English lowercase characters (a - z); (iii) Base 10 digits (0 - 9); (iv) Non-alphanumeric (For example: !, $, #, or %); (v) Unicode characters. We are not aware of password products typically available which can guarantee compliance with the requirement that all three of the parameters (alpha, numeric, and “special” characters) listed in the standard be included in passwords. Unless technical feasibility exceptions are allowed for such legacy Account Management systems, the timeframe for compliance could be significantly longer than “R+18”, “S+10” or “RO+6”.
Group
Progress Energy Nuclear Generation
Chris Georgeson
It can be improved by clarifying that the "S - Scope of Systems Determination" timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response regarding the outcome of the exemption before the "S" time clock starts. This allows time for implementation of requirements for items where an exemption request could be denied.
Individual
William Guldemond
Pacific Gas and Electric/Diablo Canyon Power Plant
Yes
Yes
No
No
No
Individual
Kirit Shah
Ameren
YES.

YES.
NO.
Yes. CIP-006-1 R1, R2, R3 currently do not allow enough time. These requirements need to be changed to outage dependent. Depending on the physical access control changes or a “six-wall” border change the plant may need to be on outage to make these changes.
No.

Consideration of Comments for the Draft Implementation Plan for Version 1 of the CIP Reliability Standards

The Order 706B Nuclear Plant Implementation Team thanks all commenters who submitted comments on the Draft Implementation Plan for Version 1 of the CIP Reliability Standards. The implementation plan was posted for a 25-day public comment period from July 20, 2009 through August 14, 2009. In order to be responsive to the September 15, 2009 filing deadline and as a reflection of the significant involvement of the nuclear community in the development of this proposal, the NERC Standards Committee approved the team to shorten the comment period and pre-ballot review period, and if necessary, offer changes to the proposal based on the comments received before proceeding to ballot.

The stakeholders were asked to provide feedback on the draft implementation plan through a special Electronic Comment Form. There were 15 sets of comments, including comments from more than 40 different people from over 25 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Based on stakeholder comments, the drafting team made the following changes to the implementation plan:

- Modified the timeframes related to refueling outages to be six months following the completion of the first refueling outage that is at least 18 months following the FERC Effective Date

- Added CIP-006-1 to the list of standards possibly associated with a refueling outage.

- Clarified that the “FERC approval” date is the “FERC approved effective date”

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 Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

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4. **Are there any requirements in CIP-003-1, CIP-004-1, CIP-006-1, and CIP-009-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States? Implementation of these standards is not believed to be predicated on an outage.** 26
5. **Are there any requirements in CIP-005-1, CIP-007-1, and CIP-008-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States? Implementation of certain aspects of these standards is believed to be predicated on an outage.** 31

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Hugh Francis	Southern Company	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andrew Neal	Southern Nuclear	SERC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Annette Bannon	PPL Supply Group					X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Heimbach	PPL Supply	RFC	6
2.	Bill DeLuca	PPL Susquehanna	RFC	5
3.	Dave Gladey	PPL Susquehanna	RFC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2									
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2									
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
7.	Manuel Couto	National Grid	NPCC	1									
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1									
9.	Brian D. Evans-Mongeon	Utility Services	NPCC	8									
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5									
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5									
12.	Kathleen Goodman	ISO - New England	NPCC	2									
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1									
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1									
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2									
16.	Greg Mason	Dynegy Generation	NPCC	5									
17.	Bruce Metruck	New York Power Authority	NPCC	6									
18.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3									
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1									
20.	Michael Schiavone	National Grid	NPCC	1									
21.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10									
4.	Individual	Alison Mackellar	Exelon Generation Company, LLC - Exelon Nuclear					X					
5.	Individual	Doug Engraf	Black & Veatch - Consulting Engineers										
6.	Individual	James Starling	SCE&G	X		X		X	X				
7.	Individual	Benjamin Church	NextEra Energy Resources, LLC					X	X				
8.	Individual	Silvia Parada-Mitchell	Generator Operator	X					X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jalal Babik		RFC	3
2.	Louis Slade		SERC	6
3.	Mike Garton		NPCC	5
4.	Bill Thompson		SERC	1
5.	Marc Gaudette		SERC	NA

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Chris Georgeson	Progress Energy Nuclear Generation					X					
11.	Individual	Janardan Amin	Luminant Power- CPNPP					X					
12.	Individual	Marcus Lotto - on behalf of SCE's subject matter experts	Southern California Edison Company	X		X		X	X				
13.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
14.	Individual	William Guldemond	Pacific Gas and Electric/Diablo Canyon Power Plant					X					
15.	Individual	Kirit Shah	Ameren	X		X		X	X				

1. Does the *structure* of the timeframe for compliance represent a reasonable approach that acknowledges the critical path items that could impact implementation of the CIP requirements?

Summary Consideration: Commenters generally indicated support for the timeframes but were not clear whether the Scope of Systems Determination included the time to request and receive a response to the exemption request. The team believes the Scope of Systems Determination includes the availability of the exemption process but not the invocation of the process.

Organization	Question 1 Comment
Southern Company	Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the “S “Scope of Systems Determination? timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. Southern Company would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
Response: The reference to the scope of system determination, identified by “S” in the “Timeframe to Compliance” column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC’s CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	

Organization	Question 1 Comment
PPL Supply Group	The structure of the timeframe is reasonable. It reflects the critical path items for the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. The "S" designation is not clear that it includes time to file for an exemption. PPL would like to ensure that the S timeframe allow time for the entity to review the requirements, file for an exemption, and receive a response on the outcome before the S time clock starts.
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	
Northeast Power Coordinating Council	The structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is adequate, there are a few clarifications that need to be made to it. While the definition of the "S "Scope of Stems Determination? timeframe includes a statement that the exemption process is included, it is not clear if it includes time to file for the exemption. It should be ensured that the "S" timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the "S" time clock starts. Is the "S" timeframe intended to allow for the exemption process to be complete before the clock starts?
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that	

Organization	Question 1 Comment
would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Mermorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	
Exelon Generation Company, LLC - Exelon Nuclear	The structure of the timeframe for compliance presents a generally reasonable approach; however, given that the nuclear industry has not yet performed an assessment in accordance with CIP-002 (R.2, R.3) the scope is difficult to determine.
Response: The team thanks you for your comments.	
Black & Veatch - Consulting Engineers	We are concerned the time frame between the plant determining the SSCs that are subject to FERC jurisdiction with Memo of Understanding between NERC and NRC and the time to acceptance of that memo. In other words, we are concerned that NERC or the NRC might not accept the SSCs as submitted and the plant's work plan may need significant changes. We would like to see the time to completion tied to acceptance of the SSC list by the NRC and NERC.
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling	

Organization	Question 1 Comment
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SCE&G	Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements. While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the “S “ Scope of Systems Determination? timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. South Carolina Electric & Gas would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
Response: The reference to the scope of system determination, identified by “S” in the “Timeframe to Compliance” column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC’s CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that	

Organization	Question 1 Comment
contain multiple units as the linkage to refueling outages is unit-specific.	
NextEra Energy Resources, LLC	Yes, in general the basic structure provides a foundation to establish the correct schedule to implement the reliability standards. One area of concern is in the detail of "S - Scope of Systems Determination" date. There is uncertainty as to whether the MOU between NERC and the NRC will include a matrix or other methodology that will clearly define standard plant systems assigned to NERC or the NRC (i.e., identify the "bright line"). Determination of the "bright line" can also be accomplished by including a period for nuclear plants to evaluate the exemption process, file for exemptions, and receive rulings on filed exemptions. This approach should allow adequate time completion of the exception process before declaring the "S" date.
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	
Generator Operator	Yes, in general the basic structure provides a foundation to establish the correct schedule to implement the reliability standards. One area of concern is in the detail of "S - Scope of Systems Determination" date. There is uncertainty as to whether the MOU between NERC and the NRC will include a matrix or other methodology that will clearly define standard plant systems assigned to NERC or the NRC (i.e., identify the "bright line"). Determination of the "bright line" can also be accomplished by including a period for nuclear plants to evaluate the exemption process, file for exemptions, and receive rulings on filed exemptions. This approach should allow adequate time completion of the exception process before declaring the "S" date.

Organization	Question 1 Comment
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	
Electric Market Policy	The structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements.While the structure is adequate, there are a few clarifications that need to be made to the structure. While the definition of the "S " Scope of Stems Determination? timeframe includes a statement that the exemption process is included, it is not clear if it includes time to file for the exemption.Dominion would like to ensure the "S" timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the "S" time clock starts. Is the "S" timeframe intended to allow for the exemption process to be complete before the clock starts?
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling	

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<tr><td>Progress Energy Nuclear Generation</td><td>It can be improved by clarifying that the "S - Scope of Systems Determination" timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response regarding the outcome of the exemption before the "S" time clock starts. This allows time for implementation of requirements for items where an exemption request could be denied.</td></tr>
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Organization	Question 1 Comment
	requirements.While the structure is accurate there are a few clarifications that need to be made to the associated timeframes. While the definition of the “S “ Scope of Systems Determination timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption. Luminant Power would like to ensure the “S” timeframe allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?
Response: The reference to the scope of system determination, identified by “S” in the “Timeframe to Compliance” column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC’s CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.	
Southern California Edison Company	Yes, the structure of the timeframe is a reasonable approach for the implementation of the CIP requirements at the nuclear plants. The implementation plan accurately reflects the critical path items for the development of the MOU between NERC and the NRC and it also recognizes that a refueling outage is required to implement a portion of the requirements.While the structure is accurate there are a few clarifications that need to be made to the structure. While the definition of the “S “ Scope of Systems Determination? timeframe includes a statement that the exemption process is included it is not clear if it includes time to file for the exemption.Southern California Edison would like to ensure the “S” time frame allows time for the entity to review the requirements, file for an exemption, and receive a response on the outcome of the exemption before the “S” time clock starts. Is the “S” timeframe intended to allow for the exemption process to be complete before the clock starts?One other item that should be taken into consideration is that the proposed timeline identified in the implementation plan is contingent, in part, on the development of the Memorandum of Understanding (MOU) between NERC and NRC. Because the MOU is intended to address both the

Organization	Question 1 Comment
	"exception process" and audit responsibilities, SCE is concerned with the lack of transparency in MOU development. SCE believes stakeholders would have valuable input into the MOU development, input that would ultimately benefit the industry. Therefore, SCE strongly recommends the MOU development include direct stakeholder participation, or at minimum, solicitation of stakeholder comment prior to adoption.
Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific. The NERC-NRC Memorandum of Understanding is outside the scope of the implementation plan activity that is the subject of this comment period. We will forward your comments to those at NERC working to develop the MOU.	
Duke Energy	Overall, the structure represents a reasonable approach. However, as described in the implementation plan, the "S" (Scope of Systems Determination) seems to include only completion of the NERC/NRC MOU and establishment of the exemption process. 10 months following "S" is barely adequate time for an entity to review the Scope of Systems Determination, identify exemptions and seek NERC approval of the exemptions. NERC will then need time to process exemption requests. NERC's denial of an exemption should be the event which starts the clock on the "S+10" month timeframe for compliance. That point of denial by NERC would place the item "in scope" and the clock for implementation of CIP standards for that item would start. "S+10" would mean that 10 months after denial of the exemption by NERC you would have to be in compliance. Also, defining "RO" as the first refueling outage 12 months after the FERC effective date does not allow adequate time to design, develop, budget, plan and implement modifications requiring a refueling outage, since some utilities are on a 24-month refueling cycle. "RO" should be defined as the first refueling outage greater than 24 months after the FERC effective date. However, in cases where

Organization	Question 1 Comment
	exemptions are sought for items that require a refueling outage and are subsequently denied by NERC, "RO" should be the first refueling outage greater than 24 months after the denial of the exemption by NERC.

Response: The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memoraundum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The actual invocation of the exemption process is not included in this timeframe. However, NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant.

The amended implementation plan includes three timeframes. The first pertains to requirements not tied to the need for a refueling outage. In these cases, the implementation timeframe is the FERC effective date plus 18 months. For those requirements that are outage-dependent, the timeframe to compliance is six months following the first refueling outage at least 18 months from the FERC Effective Date. And the final component is the scope of systems determination for which the timeframe to compliance is ten months following the completion of the Memorandum of Understanding and the estalbishment of the exemption process. The controlling timeframe for implementation is the later of the three. As the completion of the Memorandum of Understanding and the availability of the exemption process is expected in the next few months, the controlling timeframe is expected to be the FERC Effective Date plus 18 months. Given that each nuclear power plant is required to file a comprehensive cyber security plan with the NRC in November, 2009, the team believes sufficient time exists for an entity to invoke and receive disposition of the request for exemption before the NERC CIP standards take effect. To be clear, the implementation timeframes for CIP requirements are intended to be applied on a per unit basis for those plants that contain multiple units as the linkage to refueling outages is unit-specific.

The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.

Organization	Question 1 Comment
Pacific Gas and Electric/Diablo Canyon Power Plant	Yes
Ameren	YES.

2. Does the proposed implementation plan generally provide a reasonable timeframe for implementing NERC's CIP Version 1 standards at nuclear power plants?

Summary Consideration: Commenters expressed concern that the timeframes associated with a refueling outage may not be sufficient to fully design and implement changes in support of the CIP standards. The team agreed and modified the timeframes related to refueling outages to be six months following the completion of the first refueling outage that is at least 18 months following the FERC Effective Date.

Organization	Question 2 Comment
Southern Company	With the exception of the above comment, concerning the "S" timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC Effective Date?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the	

Organization	Question 2 Comment
refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
PPL Supply Group	PPL does not feel the timeframe allowed for outage activities will provide enough time for identifying solutions, planning, and implementing the requirements. The order of compliance within 12 months is too short considering once each unit is identified as a critical asset, the critical asset changes budgeted and designed, and then planning and implementing the changes via the work management system. The current implementation schedule is determined as the latter of R+18, S+10, or RO+6. This becomes apparent when an outage would begin 13-14 months after FERC approval. This would require a plant to be compliant in 19-20 months. When we add up all of the design, plan, implement timeframes utilizing our process this would take 24 months...in this case we would have to be compliant in 7-10 months. Therefore the definition of RO needs to change to next refueling outage beyond 18 months of the FERC effective date.
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other aspects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Northeast Power Coordinating Council	With the exception of the above comment concerning the "S" timeframe, the timeframes are reasonable for implementing CIP requirements for the items that do not require a refueling outage to implement. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements, each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activitiy is required 12 months after the FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included in the next refueling outage.With the current implementation schedule, each unit would be required to be compliant the latter of R+18, S+10 or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is

Organization	Question 2 Comment
	complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant, then the total time required would be 24 months. In this scenario, the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation.In order to allow for adequate time to identify, plan, budget and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC effective date.?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Exelon Generation Company, LLC - Exelon Nuclear	The proposed implementation plan generally provides a reasonable timeframe for implementing NERC's CIP Version 1 except as noted in the response to other questions, below.In addition, it is our understanding that "Auditably Compliant" will be required one year following the compliance milestone defined in the implementation plan. "Auditably Compliant" means the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable "data," "documents," "documentation," "logs," and "records."
Response: The team agrees with your description of "Auditably Compliant"	
Black & Veatch - Consulting Engineers	The time frame is acceptable as long as long as it is tied to the agreement on which SSCs require NERC CIP compliance.
Response: Agreed.	
SCE&G	With the exception of the previous comment, concerning the "S" timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements the unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once the unit is identified as a critical asset, the critical cyber assets will need to be identified. Once

Organization	Question 2 Comment
	the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC Effective Date?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
NextEra Energy Resources, LLC	The prerequisite approvals or activities do not allow for adequate time to implement a compliant program as follows: 1) Nuclear plants will need 12 months to identify assets and any mitigation items that will be required for compliance to CIP-002. Also, there may be plant design changes required in support of the program requirements. Industry standard "fast track" design changes take 9 months to complete which includes completing the detailed design and establishing complete configuration documentation. Implementation of the engineering design takes an additional 3 months to prepare instructions and complete the work which must be coordinated within the plant work management process. This requires R+24 to perform implementation. 2) Comments from question 1 above identifies the adjustment to "S". 3) Design changes that require a refueling outage impact generation or the safe operation of the plant. Refueling Outages are budgeted, engineered, and planned with longer lead times due to the complexity of work activities. The proposed implementation plan will require some facilities to execute design change packages without adequate time to meet the refueling planning window of 24 months. Adding the 24 months for the refueling design and planning window implementation to the previously stated 12 months for the completion of CIP-002 requires a refueling outage 36 months from the effective date. Some plants have longer fuel cycles so it is

Organization	Question 2 Comment
	recommended the RO effective date is "First refueling outage beyond R +18 month+ one fuel cycle".
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Generator Operator	The prerequisite approvals or activities do not allow for adequate time to implement a compliant program as follows: 1) Nuclear plants will need 12 months to identify assets and any mitigation items that will be required for compliance to CIP-002. Also, there may be plant design changes required in support of the program requirements. Industry standard "fast track" design changes take 9 months to complete which includes completing the detailed design and establishing complete configuration documentation. Implementation of the engineering design takes an additional 3 months to prepare instructions and complete the work which must be coordinated within the plant work management process. This requires R+24 to perform implementation. 2) Comments from question 1 above identifies the adjustment to "S". 3) Design changes that require a refueling outage impact generation or the safe operation of the plant. Refueling Outages are budgeted, engineered, and planned with longer lead times due to the complexity of work activities. The proposed implementation plan will require some facilities to execute design change packages without adequate time to meet the refueling planning window of 24 months. Adding the 24 months for the refueling design and planning window implementation to the previously stated 12 months for the completion of CIP-002 requires a refueling outage 36 months from the effective date. Some plants have longer fuel cycles so it is recommended the RO effective date is "First refueling outage beyond R +18 month+ one fuel cycle".
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	

Organization	Question 2 Comment
Electric Market Policy	With the exception of the above comment, concerning the "S" timeframe, the timeframes are reasonable for implementing CIP requirements for the items that do not require a refueling outage to implement. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements, each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activitiy is required 12 months after the FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included in the next refueling outage.With the current implementation schedule, each unit would be required to be compliant the latter of R+18, S+10 or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant, then the total time required would be 24 months. In this scenario, the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation.In order to allow for adequate time to identify, plan, budget and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC effective date.?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Luminant Power-CPNPP	With the exception of the above comment, concerning the "S" timeframe, the items that do not require a refueling outage to implement, the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC

Organization	Question 2 Comment
	effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified, a design change will need to be developed, planned and budgeted to be included into the next refueling outage. With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation. In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC Effective Date?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Southern California Edison Company	With the exception of the above comment, concerning the “S” timeframe, the items that do not require a refueling outage to implement the timeframes are reasonable for implementing the CIP requirements. However, we do not feel the timeframe allowed for outage activities will provide enough time for identification, planning and implementing the requirements. The current plan provides a timeframe for outage activities of the first refueling outage 12 months after FERC approval. In order to comply with the requirements each unit will first need to be evaluated against the CIP-002 requirements and be identified as a critical asset. Compliance with this activity is required 12 months after FERC effective date. Once each unit is identified as a critical asset, the critical cyber assets will need to be identified. Once the critical cyber assets are identified a design change will need to be developed, planned and budgeted to be included into the next refueling outage.With the current implementation schedule each unit would be required to be compliant the latter of R+18, S+10, or RO+6. The worst case scenario is if an outage is scheduled to begin 13-14 months after FERC approval. The current timeframe would require the unit to have a plan, including design change, approval of the budget, implemented and documentation updated in 19-20 months to be compliant. In order to

Organization	Question 2 Comment
	effectively plan and budget for the changes, we would first need to develop a design change. A design change of this type would take a minimum of 6 months. Once the development of the design change is complete we could accurately plan and budget for the change. This will take an additional 6 months. If the identification requires 12 months to be compliant then the total time required would be 24 months. In this scenario the plant is allowed approximately 7-10 months, after identifying it as a critical asset, to develop a design change, plan, implement and update the documentation.In order to allow for adequate time to identify, plan, budget, and implement the required design changes, the definition of RO should be: RO=Next refueling outage beyond 18 months of FERC Effective Date?
Response: The team agrees that the part of the implementation plan linked to refueling outages is confusing relative to other apsects of the implementation plan, particularly in the timeframe 12-18 months following the FERC Effective Date. Therefore, for simplicity and to recognize that the controlling timeframe will be at least 18 months following the FERC Effective Date, the team has modified the implementation timeframes for those requirements linked to refueling outages to be six months following the first refueling outage that is at least 18 months from the FERC Effective Date. The team believes this approach simplifies the plan by targeting implementation for those requirements not tied to an outage at 18 months following the FERC Effective Date, or for those requirements that are outage-related, at six months following the first refueling outage that is at least 18 months following the FERC Effective Date. The six months identified for the refueling outage permits the entity to complete the necessary documentation for the modification or activities that were undertaken during the outage.	
Duke Energy	Timeframes are suitable, except for our concern as noted in response to Question #1 above.
Response: Thank you for your comment	
Pacific Gas and Electric/Diablo Canyon Power Plant	Yes
Ameren	YES.

3. Are there any requirements in CIP-002-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States?

Summary Consideration: Commenters indicated that except as identified in earlier questions, the timeframes are suitable.

Organization	Question 3 Comment
Southern Company	With the exception of the comment to question 1 the time frames are suitable.
PPL Supply Group	With the exception of the comment to question 1, the time frames are acceptable.
Response: Thank you for your comment	
Northeast Power Coordinating Council	With the exception of the comment to Question 1, the timeframes are suitable.
Response: Thank you for your comment	
Exelon Generation Company, LLC - Exelon Nuclear	The proposed time frame is suitable for implementation; however, the execution of the identification of a critical asset and identification of critical cyber assets will present a challenge especially during the later milestones that include final review and signoff from senior executives.
Response: Thank you for your comment	
Black & Veatch - Consulting Engineers	should not be a problem
Response: Thank you for your comment	
SCE&G	With the exception of the comment to question 1 the time frames are suitable.
Response: Thank you for your comment	
NextEra Energy	See comments from question 1 and 2 above for time frame comments. Implementation of the CIP standards on some Balance

Organization	Question 3 Comment
Resources, LLC	of Plant systems is focused on regulatory compliance and the alignment of processes. Due to compliance with NEI 04-04, the industry has implemented cyber security barriers that protect generation and there is no cyber security or reliability gap.
Response: Thank you for your comment	
Generator Operator	See comments from question 1 and 2 above for time frame comments. Implementation of the CIP standards on some Balance of Plant systems is focused on regulatory compliance and the alignment of processes. Due to compliance with NEI 04-04, the industry has implemented cyber security barriers that protect generation and there is no cyber security or reliability gap.
Response: Thank you for your comment	
Electric Market Policy	With the exception of the comment to Question 1, the time frames are suitable.
Response: Thank you for your comment	
Progress Energy Nuclear Generation	
Luminant Power- CPNPP	With the exception of the comment to question 1 the time frames are suitable.
Southern California Edison Company	With the exception of the comment to question 1, the time frames are suitable.
Response: Thank you for your comment	
Duke Energy	Timeframes are suitable, except for our concern as noted in response to Question #1 above.
Response: Thank you for your comment	
Pacific Gas and Electric/Diablo Canyon Power Plant	No
Ameren	NO.

4. Are there any requirements in CIP-003-1, CIP-004-1, CIP-006-1, and CIP-009-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States? Implementation of these standards is not believed to be predicated on an outage.

Summary Consideration: Several commenters indicated concern over CIP-006-1 not being available for implementation except during a refueling outage timeframe. The team agreed and included CIP-006-1 on the list of standards possibly associated with a refueling outage. Other commenters indicated that all standards should have their implementation plan linked to refueling outages. The team does not believe this is appropriate and that non-outage related approaches are available to meet the intent of the remaining requirements.

Organization	Question 4 Comment
Southern Company	With the exception of the comment to question 1 the time frames are suitable.While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent and perhaps automated solutions during the next refueling outage opportunity.	
PPL Supply Group	With the exception of the comment to question 1, the time frames are acceptable.
Response: Thank you for your comment.	
Northeast Power Coordinating Council	With the exception of the comment to Question 1, the timeframes are suitable. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance, R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe

Organization	Question 4 Comment
	should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent and perhaps automated solutions during the next refueling outage opportunity.	
Exelon Generation Company, LLC - Exelon Nuclear	For CIP-003-1, CIP-006-1, and CIP-009-1, No. For CIP-004-1, the proposed time frame is reasonable; however, depending on the identified personnel within scope, completion of the training program (R.2) may be a challenge to have completed by the later of the R+18 or S+10 timeframes.
Response: The team does not agree with the suggestion to modify the implementation timeframes for training program requirements in CIP-004-1. The entity's training program can include provisions to exclude personnel who have not completed the training program with the understanding that the person would not have access or be included on access lists for CCAs prior to the training being completed.	
Black & Veatch - Consulting Engineers	With regard to CIP-009-1, deployment of some types of backup and restore systems (including development of complete system backups of CCA's), might be best performed during an outage to prevent impact traffic to ESP network.
Response: The team appreciates the comment but believes CIP-009-1 is appropriately classified. As the language in the requirement states, Requirement R4 requires the development of the process and procedures for backup and restore; it does not require a technical control that would require an outage to implement. Further, the team believes the implementation of those processes and procedures could be performed manually and would also not require an outage	
SCE&G	CIP-003-1: With the exception of the comment to question 1 the time frames are suitable. CIP-004-1: With the exception of the comment to question 1 the time frames are suitable. CIP-006-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement cannot be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process. CIP-009-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement cannot be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6)

Organization	Question 4 Comment
	should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
NextEra Energy Resources, LLC	See comments from question 1 and 2 above for time frame comments. Until detailed assessments are completed, it is generally unknown if there are items that can not be installed without a design change during a refueling outage to fully meet all requirements in CIP R03,R04, R06, and R09. The plant should be able to assess the need for a refueling outage to completely satisfy the requirements and provide final reporting during the self certification process.See comments from question 3 above for comments on no reliability gap.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
Generator Operator	See comments from question 1 and 2 above for time frame comments. Until detailed assessments are completed, it is generally unknown if there are items that can not be installed without a design change during a refueling outage to fully meet all requirements in CIP R03,R04, R06, and R09. The plant should be able to assess the need for a refueling outage to completely satisfy the requirements and provide final reporting during the self certification process.See comments from question 3 above for comments on no reliability gap.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
Electric Market Policy	With the exception of the comment to Question 1, the time frames are suitable. While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per

Organization	Question 4 Comment
	CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
Progress Energy Nuclear Generation	
Luminant Power-CPNPP	For CIP-003-1, CIP-004-1: With the exception of the comment to question 1 the time frames are suitable.For CIP-006-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification processFor CIP-009-1: While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
Southern California Edison Company	With the exception of the comment to question 1 the time frames are suitable.While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-

Organization	Question 4 Comment
	005, then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement. However, the team does not agree that CIP-003-1, CIP-004-1, and CIP-009-1 should be linked to a refueling outage. The team believes that there are interim solutions that could be implemented manually if necessary to meet the intent of the requirements. The entity could then determine the appropriateness of installing more permanent, and perhaps automated solutions during the next refueling outage opportunity	
Duke Energy	The implementation plan for CIP-006-1 requirements doesn't include any "RO+6" timeframes. Depending upon how the physical security plan is implemented, some elements of it might require a refueling outage. Otherwise, timeframes are suitable, except for our concern as noted in response to Question #1 above.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement.	
Pacific Gas and Electric/Diablo Canyon Power Plant	No
Ameren	Yes. CIP-006-1 R1, R2, R3 currently do not allow enough time. These requirements need to be changed to outage dependent. Depending on the physical access control changes or a "six-wall" border change the plant may need to be on outage to make these changes.
Response: The team has re-evaluated CIP-006-1 and modified the implementation plan to include CIP-006-1 in the list of standards that could potentially require an outage to implement. The implementation of physical controls, particularly outside the protected area, could require an outage to fully implement.	

5. Are there any requirements in CIP-005-1, CIP-007-1, and CIP-008-1 for which the time frame is not suitable for implementation, either not enough time or too much time, to ensure there is no reliability gap in coverage for the balance of plant items at the nuclear power plants in the United States? Implementation of certain aspects of these standards is believed to be predicated on an outage.

Summary Consideration: No concern expressed with respect to these standards except for the time concerns addressed earlier regarding refueling outages.

Organization	Question 5 Comment
Southern Company	With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details.While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005 then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: See responses to earlier questions**.**	
PPL Supply Group	With the exception of the items that require an outage to implement, the timeframes are acceptable. For the items that require an outage to perform, the timeframes are not acceptable, see answer to question 2 above. Consideration needs to be given in these CIPs for the possibility of having to fully implement them in an outage and depends upon the strategy implemented under CIP-005-1.
Response: See responses to earlier questions	
Northeast Power Coordinating Council	With the exception of the items that require an outage to perform, the time frames are not acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See response to Question 2 above for details.While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.

Organization	Question 5 Comment
Response: See responses to earlier questions	
Exelon Generation Company, LLC - Exelon Nuclear	No. The time frames for the requirements in CIP-005-1, CIP-007-1, and CIP-008-1 are suitable for implementation.
Response: See responses to earlier questions	
Black & Veatch - Consulting Engineers	Refer to response to Question #1 - If the timeframe is not tied to the NRC and NERC acceptance of the SSC list, the schedule for deployement of the required network security systems, including potential upgrades to existing systems, may be of concern.
Response: See responses to earlier questions	
SCE&G	CIP-005-1: The time frames allowed for implementing these requirements are not suitable. See answer to question 2 above for details. CIP-007-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details. CIP-008-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details.
Response: See responses to earlier questions	
NextEra Energy Resources, LLC	See comments from question 1 and 2 above for time frame comments.See comments from question 3 above for comments on no reliability gap.
Generator Operator	See comments from question 1 and 2 above for time frame comments.See comments from question 3 above for comments on no reliability gap.
Response: See responses to earlier questions	
Electric Market Policy	With the exception of the items that require an outage to perform, the time frames are not acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See response to Question 2 above for details.While these requirements do not require an outage to implement, they are dependent on the strategy implemented under CIP-005. For instance R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design change to install the access controls per CIP-005, then this requirement cannot be met until the design change is

Organization	Question 5 Comment
	implemented. This is also true for R5 and R6. The Outage dependent column for these requirements (R4, R5 and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self-certification process.
Response: See responses to earlier questions	
Progress Energy Nuclear Generation	
Luminant Power-CPNPP	For CIP-005-1:The time frames allowed for implementing these requirements are not suitable. See answer to question 2 above for details.For CIP-007-1 & CIP-008-1: With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details.
Response: See responses to earlier questions	
Southern California Edison Company	With the exception of the items that require an outage to perform, the time frames are acceptable. For the items that require an outage to perform, the time frames allowed are not suitable. See answer to question 2 above for details. While these requirements do not require an outage to implement they are dependent on the strategy implemented under CIP-005-1. For instance, R4 requires the entity to log access 24 hours a day, 7 days a week. If the plant identifies the need for a design to install the access controls per CIP-005, then this requirement can not be met until that design is implemented. This is also true for R5 and R6. The Outage Dependent column for these requirements (R4, R5, and R6) should be labeled as Possible and the RO+6 timeframe should be included. The entity should be able to assess the need for an outage to satisfy these requirements and report that during the self certification process.
Response: See responses to earlier questions	
Duke Energy	In addition to our concern noted in response to Question #1 above, we have a concern with Requirement R3 of CIP-007-1 which requires installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s). There are many cyber security system devices such as relays and programmable logic controllers which cannot accept software patches. NERC's technical feasibility exception process doesn't currently allow an exemption for Requirement R3. If such devices will be required to meet R3, then the timeframe for compliance would be significantly longer than "RO+6". In some cases, CIP-compliant replacement equipment may not even be available for nuclear-grade applications, and we could NEVER achieve compliance.Similarly, Requirement R5.3.2 requires that passwords shall consist of a combination of alpha, numeric, and "special" characters. Commonly used tools, including Active Directory can enforce password parameters such the following: The password contains characters from at least three of the following five

Organization	Question 5 Comment
	categories: (i) English uppercase characters (A - Z); (ii) English lowercase characters (a - z); (iii) Base 10 digits (0 - 9); (iv) Non-alphanumeric (For example: !, $, #, or %); (v) Unicode characters. We are not aware of password products typically available which can guarantee compliance with the requirement that all three of the parameters (alpha, numeric, and "special" characters) listed in the standard be included in passwords. Unless technical feasibility exceptions are allowed for such legacy Account Management systems, the timeframe for compliance could be significantly longer than "R+18", "S+10" or "RO+6".
Response: The existing R3.2 language permits a technical feasibility exception already. This requirement states: *The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk. and permits the entity* Therefore, the team believes the commenter's concern, while valid, is already addressed through R3.2 provisions. Requirement R5.3.2 already is included on the list of requirements for which a technical feasibility exception can be requested.	
Pacific Gas and Electric/Diablo Canyon Power Plant	No
Ameren	No.

Standards Announcement
Initial Ballot Window Open
August 19–28, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Cyber Security — Order 706B Nuclear Plant Implementation Plan
An initial ballot window for an implementation plan for Version 1 critical infrastructure protection (CIP) Reliability Standards CIP-002-1 through CIP-009-1 for Nuclear Power Plants is now open **until 8 p.m. EDT on August 28, 2009**.

Special Notes for This Project
In order to be responsive to the September 15, 2009 filing deadline and as a reflection of the significant involvement of the nuclear community in the development of this proposal, the NERC Standards Committee approved the team to shorten the comment period and hold the comment period at the same time as the pre-ballot review period, and if necessary, offer changes to the proposal based on the comments received before proceeding to ballot. The comment period and pre-ballot review ended on August 14, 2009. The drafting team modified the implementation plan based on stakeholder input; the two significant revisions are listed below:

1. Included CIP-006-1 on the list of standards potentially requiring an outage to implement
2. Adjusted the implementation timeframe for refueling outages to six months beyond the first refueling outage that is at least 18 months following the FERC effective date

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
Voting results will be posted and announced after the ballot window closes.

Project Background
On January 18, 2008, FERC (or "Commission") issued Order No. 706 that approved Version 1 of the CIP Reliability Standards: CIP-002-1 through CIP-009-1. On March 19, 2009, the Commission issued clarifying Order No. 706-B that clarified "the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory "CIP" Reliability Standards approved in Commission Order No. 706." However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, the Commission noted in ¶59 that,

> "[i]t is not appropriate to dictate the schedule contained in Table 3 of NERC's Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.
>
> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants' full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule."

This project addresses the development of the implementation plan specific for nuclear power plants. The draft plan was drafted by members of the original Version 1 Cyber Security Drafting Team with specific outreach to nuclear power plant owners and operators to ensure their interests were fairly represented.

Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Cyber Security — Order 706B Nuclear Plant Implementation Plan

The initial ballot for an implementation plan for Version 1 critical infrastructure protection (CIP) Reliability Standards CIP-002-1 through CIP-009-1 for Nuclear Power Plants ended on August 28, 2009.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 81.96%
Approval: 97.37%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria details are listed at the end of the announcement.

Next Steps

As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

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1. Included CIP-006-1 on the list of standards potentially requiring an outage to implement
2. Adjusted the implementation timeframe for refueling outages to six months beyond the first refueling outage that is at least 18 months following the FERC effective date

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Order 706-B Nuclear Implementation Plan_in
Ballot Period:	8/19/2009 - 8/28/2009
Ballot Type:	Initial
Total # Votes:	159
Total Ballot Pool:	194
Quorum:	**81.96 % The Quorum has been reached**
Weighted Segment Vote:	97.37 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	48	1	31	0.939	2	0.061	6	9
2 - Segment 2.	9	0.3	3	0.3	0	0	2	4
3 - Segment 3.	47	1	30	1	0	0	11	6
4 - Segment 4.	10	0.5	5	0.5	0	0	3	2
5 - Segment 5.	34	1	22	0.957	1	0.043	8	3
6 - Segment 6.	26	1	16	0.941	1	0.059	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	6	0.6	0	0	0	2
9 - Segment 9.	5	0.2	2	0.2	0	0	1	2
10 - Segment 10.	7	0.6	6	0.6	0	0	0	1
Totals	**194**	**6.2**	**121**	**6.037**	**4**	**0.163**	**34**	**35**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Affirmative	View
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	Farmington Electric Utility System	Alan Glazner		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	JEA	Ted E. Hobson	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Kissimmee Utility Authority	Joe B Watson	Affirmative	
1	Lakeland Electric	Larry E Watt	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	MEAG Power	Danny Dees	Affirmative	
1	National Grid	Manuel Couto		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	Oncor Electric Delivery	Charles W. Jenkins		
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Abstain	
1	Westar Energy	Allen Klassen		
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	BC Transmission Corporation	Faramarz Amjadi	Abstain	
2	California ISO	Greg Tillitson		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Abstain	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	View
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke		
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	Mark Alberter	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin L Holt		
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace		
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Constellation Power Source Generation, Inc.	Scott A Etnoyer	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	FPL Energy	Benjamin Church	Negative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Abstain	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Abstain	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Abstain	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	

5	PSEG Power LLC	Thomas Piascik	Affirmative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Luminant Energy	Thomas Burke		
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Joann Wehle		
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Edward C Stein	Edward C Stein	Affirmative	
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
8	Wally Magda	Wally Magda	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren		

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Consideration of Comments on Initial Ballot — Order 706-B Nuclear Implementation Plan

Summary Consideration:

The initial ballot received nine comments from representatives in four of ten segments. The drafting team did not make any modifications to the Order 706B Implementation Plan based on balloter comments. The commenters expressed concerns in the following areas:

- The timeframe for scope of systems determination in the plan (denoted by "S") should include time to request and receive a response to an exemption request. The drafting team addressed this item in the previous comment period and concluded the invocation of the process is not included in this timeframe.
- The timeframe for requirements related to a refueling outage is insufficient and needs to be modified to be 6 months following the first outage that is at least 18 months following the FERC effective date. The team had previously made this change prior to initiating the ballot.
- CIP-006 and CIP-007 requirements need to be identified as possibly needing a refueling outage to implement. The team had previously made this change prior to initiating the ballot.

If you feel that the drafting team overlooked your comments, 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 Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Silvia P Mitchell	Florida Power & Light Co.	6	Negative	Although partial clarification was provided to S (Scope of System Determination) and to implementation timeframes, additional consideration should be given to nuclear power plants for the development and implementation of a cyber security program that is fully compliant to the NERC CIP Reliability Standards. This additional consideration would involve a more thorough vetting of the exemption process and of the implementation timeframes that support design changes and nuclear refueling outage planning windows. The implementation timeframe is crucial for allowing adequate time to develop/implement design changes, develop/implement procedural instructions, and develop/implement proper training elements for the nuclear operators who already maintain a rigorous training schedule.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memorandum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The exemption process will contain the procedural details and a reasonable timeline to dispose of the requests as NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. However, the actual invocation of the exemption process is not included in this timeframe. Overall, the drafting team feels the proposed implementation plan respects the time needed by the nuclear power plant owners and operators to properly implement the NERC CIP standards, including specific accommodations for activities dependent on outages to implement.				
George R. Bartlett Matt Wolf Terri F Benoit Stanley M Jaskot	Entergy Corporation Entergy Services, Inc. Entergy Corporation	1 3 6 5	Affirmative	1. For CIP-002-1, CIP-003-1, CIP-004-1, CIP-006-1 and CIP-009-1, the Scope of Systems Determination (S) timeframe needs to allow additional up-front time for requesting an exemption and getting a decision on the request prior to the "S + 10 months" implementation period taking effect. If this were factored into the S timeframe, the structure of the timeframe for compliance would represent a reasonable approach that would acknowledge the critical path items which could impact implementation of the CIP requirements. 2. There is insufficient time allotted after the FERC effective date to get outage required activities fully scoped and planned. The existing definition of RO (Next Refueling Outage beyond 12 months of FERC Effective Date) should be changed to equal the next refueling outage beyond 18 months after the FERC effective date. 3. For CIP-006-1 under Requirements 4, 5 and 6, the Outage Dependent column needs to be changed from "No" to "Possible" with a RO+6 months (if applicable) timeframe. 4. For CIP-007-1 under Requirements 4 and 6, the Outage Dependent column needs to be changed from "No" to "Possible" with a RO+6 months (if applicable) timeframe.
Response: 1. Thank you for your comments. The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memorandum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The exemption process will contain the procedural details and a reasonable timeline to dispose of the requests as NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations				

Voter	Entity	Segment	Vote	Comment
and to maximize the time to become compliant. However, the actual invocation of the exemption process is not included in this timeframe. 2. In response to comments received during the industry posting of the implementation plan prior to the balloting phase, the drafting team changed the timeframe associated with a refueling outage to that suggested – RO+6 months where RO is the first refueling outage at least 18 months following the FERC effective date. Therefore, the plan ballotted already reflects this change. 3. The suggested change was made in response to comments received during the industry comment period that preceded the ballot. Therefore, the plan ballotted already reflects this change. 4. The suggested change was made in response to comments received during the industry comment period that preceded the ballot. Therefore, the plan ballotted already reflects this change.				
Jeffrey Mueller Thomas Piascik James D. Hebson	Public Service Electric and Gas Co. PSEG Power LLC PSEG Energy Resources & Trade LLC	3 5 6	Affirmative	1. PSEG believes that the structure of the timeframe is reasonable, and in the interests of moving forward is voting in favor. However, PSEG requests that the "S" timeframe be clarified to state that it is intended to allow sufficient time for the entity to review the requirements, file for an exemption and receive a response on the outcome of the exemption before the "S" time clock starts. 2. Also, PSEG does not believe that as presently written in some cases the timeframe allowed for outage activities will provide sufficient time to identify, plan and implement the CIP requirements including required design changes. Thus the definition of "RO" should be specified as the first refueling outage commencing 18 months after the FERC effective date.
Response: 1. Thank you for your comments. The reference to the scope of system determination, identified by "S" in the "Timeframe to Compliance" column, includes the time necessary to complete (1) the NERC-NRC Memorandum of Understanding; and, (2) the development of the exemption process that would permit entities to request exclusion of certain systems, structures, and components from the scope of NERC's CIP standards. The Memorandum of Understanding, to be completed in the next few months, is expected to contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction. The exemption process will contain the procedural details and a reasonable timeline to dispose of the requests as NERC understands the need to process exemption requests efficiently to ensure entities are clear on expectations and to maximize the time to become compliant. However, the actual invocation of the exemption process is not included in this timeframe.				

Voter	Entity	Segment	Vote	Comment
2. In response to comments received during the industry posting of the implementation plan prior to the balloting phase, the drafting team changed the timeframe associated with a refueling outage to that suggested – RO+6 months where RO is the first refueling outage at least 18 months following the FERC effective date. Therefore, the plan ballotted already reflects this change.				
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Affirmative	Regarding the CIP-005 question which is on R4.2.2: we would prefer clarification to the last sentence "Devices controlling access into the Electronic Security Perimeter are not exempt." Suggest removing or replacing with "Devices controlling access into the Electronic Security Perimeter must comply with the Standards, as described in CIP-005 R1.5.".
Response: Thank you for your comment. The issue raised relates to a change in the language of the standard itself and is outside the scope of this team's activities that is solely focused on the implementation plan.				

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Standards Announcement
Recirculation Ballot Window Open
September 1–10, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Cyber Security — Order 706B Nuclear Plant Implementation Plan

A recirculation ballot window for an implementation plan for Version 1 critical infrastructure protection (CIP) Reliability Standards CIP-002-1 through CIP-009-1 for Nuclear Power Plants is now open **until 8 p.m. EDT on September 10, 2009**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Process

The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

On January 18, 2008, FERC (or "Commission") issued Order No. 706 that approved Version 1 of the CIP Reliability Standards: CIP-002-1 through CIP-009-1. On March 19, 2009, the Commission issued clarifying Order No. 706-B that clarified "the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory "CIP" Reliability Standards approved in Commission Order No. 706." However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, the Commission noted in ¶59 that,

> "[i]t is not appropriate to dictate the schedule contained in Table 3 of NERC's Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.

> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants' full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule."

This project addresses the development of the implementation plan specific for nuclear power plants. The draft plan was drafted by members of the original Version 1 Cyber Security Drafting Team with specific outreach to nuclear power plant owners and operators to ensure their interests were fairly represented.

Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Special Notes for This Project

In order to be responsive to the September 15, 2009 filing deadline and as a reflection of the significant involvement of the nuclear community in the development of this proposal, the NERC Standards Committee approved the team to shorten the comment period and hold the comment period at the same time as the pre-ballot review period, and if necessary, offer changes to the proposal based on the comments received before proceeding to ballot. The comment period and pre-ballot review ended on August 14, 2009. The drafting team modified the implementation plan based on stakeholder input; the two significant revisions are listed below:

1. Included CIP-006-1 on the list of standards potentially requiring an outage to implement
2. Adjusted the implementation timeframe for refueling outages to six months beyond the first refueling outage that is at least 18 months following the FERC effective date

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Final Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Cyber Security — Order 706B Nuclear Plant Implementation Plan

The recirculation ballot for an implementation plan for Version 1 critical infrastructure protection (CIP) reliability standards CIP-002-1 through CIP-009-1 for nuclear power plants ended September 10, 2009.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 87.11%
Approval: 97.18%

The ballot pool approved the implementation plan. Ballot criteria details are listed at the end of the announcement.

Next Steps

The implementation plan will be submitted to the NERC Board of Trustees for adoption.

Project Background

On January 18, 2008, FERC (or "Commission") issued Order No. 706 that approved Version 1 of the CIP standards: CIP-002-1 through CIP-009-1. On March 19, 2009, the Commission issued clarifying Order No. 706-B that clarified "the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory "CIP" Reliability Standards approved in Commission Order No. 706." However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, the Commission noted in ¶59 that,

> "[i]t is not appropriate to dictate the schedule contained in Table 3 of NERC's Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.
>
> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to

> develop a more appropriate timeframe for nuclear power plants' full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule."

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Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Order 706-B Nuclear Implementation Plan_rc
Ballot Period:	9/1/2009 - 9/10/2009
Ballot Type:	recirculation
Total # Votes:	169
Total Ballot Pool:	194
Quorum:	**87.11 % The Quorum has been reached**
Weighted Segment Vote:	97.18 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	48	1	32	0.941	2	0.059	7	7
2 - Segment 2.	9	0.4	4	0.4	0	0	2	3
3 - Segment 3.	47	1	31	0.969	1	0.031	11	4
4 - Segment 4.	10	0.6	6	0.6	0	0	3	1
5 - Segment 5.	34	1	22	0.957	1	0.043	8	3
6 - Segment 6.	26	1	18	0.947	1	0.053	3	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.7	7	0.7	0	0	0	1
9 - Segment 9.	5	0.2	2	0.2	0	0	1	2
10 - Segment 10.	7	0.7	7	0.7	0	0	0	0
Totals	**194**	**6.6**	**129**	**6.414**	**5**	**0.186**	**35**	**25**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Affirmative	View
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	Farmington Electric Utility System	Alan Glazner		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	JEA	Ted E. Hobson	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Kissimmee Utility Authority	Joe B Watson	Affirmative	
1	Lakeland Electric	Larry E Watt	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	MEAG Power	Danny Dees	Affirmative	
1	National Grid	Manuel Couto		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Abstain	
1	Oncor Electric Delivery	Charles W. Jenkins		
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Abstain	
1	Westar Energy	Allen Klassen	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	BC Transmission Corporation	Faramarz Amjadi	Abstain	
2	California ISO	Greg Tillitson	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Abstain	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	View
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke		
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Sacramento Municipal Utility District	Mark Alberter	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin L Holt		
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Constellation Power Source Generation, Inc.	Scott A Etnoyer	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	FPL Energy	Benjamin Church	Negative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Abstain	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Abstain	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Abstain	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	

5	PSEG Power LLC	Thomas Piascik	Affirmative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Luminant Energy	Thomas Burke		
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Joann Wehle		
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Edward C Stein	Edward C Stein	Affirmative	
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
8	Wally Magda	Wally Magda	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Standard Authorization Request Form

Title of Proposed Standard	Implementation Plans for US Nuclear Power Plant Owners and Operators for Version 2 and Version 3 CIP Standards (CIP-002 through CIP-009)
Request Date	January 19, 2010
SC Approval Date	January 20, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Gerry Adamski	☐	New Standard
Primary Contact	Gerry Adamski	x	Revision to existing Standard
Telephone Fax	609-524-0617 609-452-9550	☐	Withdrawal of existing Standard
E-mail	gerry.adamski@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

To add specificity to the implementation plans for the Version 2 and Version 3 CIP standards for US nuclear power plant owners and operators.

Industry Need (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.)

NERC filed an implementation plan for the Version 1 CIP standards specific to US nuclear power plant owners and operators in accordance with FERC Order 706-B. However, FERC approved Version 2 of the standards to be implemented on April 1, 2010 and NERC filed Version 3 of the CIP standards in December. However, no specificity is included relative to the implementation of the Version 2 or Version 3 CIP standards for US nuclear power plant owners and operators. This project adds specificity with regard to the implementation timeline for US nuclear power plant owners and operators for the Version 2 and Version 3 CIP standards.

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

Add the expected implementation timeline for Version 2 and Version 3 CIP standards for US nuclear power plant owners and operators.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Add the following language to the implementation plans for Version 2 and Version 3 of the CIP-002 through CIP-009 to specify the implementation timeline for US nuclear power plants:

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010 and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

THIS WILL APPEAR IN A FOOTNOTE: These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	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.
☐	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.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
X	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	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 box for all that apply.)*	
☐	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.
☐	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.
☐	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	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? *(Select 'yes' or 'no' from the drop-down box.)*
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**
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standards Announcement

Standards Authorization Request (SAR) Comment Period Open
February 12–March 15, 2010

Now available at:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3
The drafting team associated with this project is seeking comments on a proposed SAR and revised implementation plans for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's critical infrastructure protection (CIP) standards **until 8 p.m. Eastern on March 15, 2010.**

Instructions
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Next Steps
The drafting team will draft and post responses to comments received during this period.

Project Background
In September 2009, NERC filed an implementation plan for the version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. Since then, FERC approved NERC's filing of the version 2 CIP standards (CIP-002-2 through CIP-009-2) to be implemented on April 1, 2010, and NERC filed version 3 of the CIP standards (CIP-002-3 through CIP-009-3) in December 2009. However, neither filing included specificity relative to the implementation of the version 2 or version 3 CIP standards for U.S. nuclear power plant owners and operators.

The purpose of this project is to add specificity with regard to the implementation timeline for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's CIP standards. Members of the original version 1 Cyber Security Drafting Team, which developed the version 1 implementation plan for U.S. nuclear power plant owners and operators, developed the language included in the revised implementation plans for the version 2 and 3 CIP standards. Detailed background information is available in the comment form.

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Unofficial Comment Form for Draft Implementation Plan for Version 2 and Version 3 Critical Infrastructure Protection Standards for Nuclear Power Plants (Project 2010-09)

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the revised draft Implementation Plans for Versions 2 and Version 3 Critical Infrastructure Protection (CIP) Reliability Standards — CIP-002 through CIP-009 for Nuclear Power Plants. Comments must be submitted by **March 15, 2010**

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

If you have questions please contact Gerry Adamski at gerry.adamski@nerc.net or by telephone at 609-524-0617.

Background Information

On December 17, 2009, FERC (or "Commission") issued an order that addressed the September 15, 2009 NERC compliance filing proposing an implementation plan for Version 1 of CIP Reliability Standards for U.S. nuclear power plant owners and operators. FERC did not approve the Version 1 implementation plan proposed but requested further information regarding the scope of systems determination that is one predicate for implementing the standards as outlined in the proposed Version 1 plan. FERC also addressed the implementation of future versions of the CIP standards at U.S. nuclear power plants. Since the September 15, 2009 filing, FERC approved Version 2 of the CIP-002 through CIP-009 Reliability Standards, and NERC proposed Version 3 in a December 29, 2009 filing. However, neither proposal addressed implementation of the standards at U.S. nuclear power plants. Accordingly, in its December 17, 2009 order, FERC provided NERC in ¶15-16 the following direction regarding implementing future versions of the CIP standards:

> 15. As mentioned above, NERC requests that the Commission "require the approved Version 2 Reliability Standards to be implemented by U.S. nuclear power plant owners and operators on a schedule no sooner than that included in the Implementation Plan that is the subject of this filing."[1] Consistent with NERC's request, the Commission finds that the implementation timeline for the Version 2 CIP Standards should be the same as the Implementation Plan for the Version 1 CIP Standards. This compliance timeline for the Version 2 CIP Standards is reasonable because the Version 2 CIP Standards comprise a limited set of modifications. Further, under the Implementation Plan's compliance schedule there is a generous lead time before the earliest possible date owners and operators of nuclear power plants will be required to achieve compliance with the Version 1 CIP Standards, which provides an adequate timeframe to achieve compliance with the Version 2 CIP Standards. This approach also reduces the gap in compliance with the CIP Standards that currently exists between nuclear power plants and other users, owners and operators of the Bulk-Power System. Therefore, we direct NERC to submit as part of its compliance filing, a revised Implementation Plan that incorporates Version 2 CIP Standards into the Implementation Plan schedule.

[1] NERC Petition at 3, 13.

16. Further, in future filings proposing modifications to the CIP Standards, NERC must address how owners and operators of nuclear power plants located in the United States will implement the revised CIP Standards and whether owners and operators can implement the revised CIP Standards under the proposed Implementation Plan. If NERC does not believe that such future modifications can be implemented under the Implementation Plan's schedule, NERC must propose in the filing a new implementation plan addressing nuclear power plant owners' and operators' compliance with the proposed modifications.

On January 19, 2010, NERC issued a compliance filing prescribed within the FERC-directed 30-day response window stating that implementation plan modifications must be processed using the approved *NERC Reliability Standards Development Procedure* and that following this activity, NERC would submit the implementation plan modifications directed by FERC. Additionally, NERC stated it will not assess U.S. nuclear power plant owners and operators for compliance to Version 2 (or Version 3) CIP reliability standards when they become effective but would address the implementation through a revised implementation plan for Version 2 and Version 3.

Members of the original Version 1 Cyber Security Drafting Team that developed the Version 1 implementation plan for U.S. nuclear owners and operators developed the following language that is included in revised implementation plans for the Version 2 and Version 3 CIP Reliability Standards, CIP-002 through CIP-009.

> *On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.*
>
> *In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.*
>
> *For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010 and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November,*

2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

THIS WILL APPEAR IN A FOOTNOTE: These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

In summary, the team is seeking industry input to the proposed Version 2 and Version 3 implementation plan language through the following questions.

1. Do you agree with the proposed implementation plan(s) generally provide a reasonable timeframe for implementing NERC's CIP Version 2 and Version 3 standards at nuclear power plants?

   ☐ Yes

   ☐ No

   Comments:

2. Does the proposed implementation plan language satisfy the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants?

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Draft Implementation Plan for Version 2 and Version 3 CIP Standards for Nuclear Power Plants (Project 2010-09)

The Cyber Security Order 706 Standard Drafting Team thanks all commenters who submitted comments on the draft implementation plan for version 2 and version 3 Critical Infrastructure Protection Standards for Nuclear Power Plants. These standards were posted for a 30-day public comment period from February 12, 2010 through March 15, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 11 sets of comments, including comments from 37 different people from over 20 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

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 Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. Do you agree with the proposed implementation plan(s) generally provide a reasonable timeframe for implementing NERC's CIP Version 2 and Version 3 standards at nuclear power plants? 6

2. Does the proposed implementation plan language satisfy the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants? 9

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Sweeney	BPA, Transmission Sales	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	NA
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Greg Mason	Dynegy Generation	NPCC	5
17.	Bruce Metruck	New York Power Authority	NPCC	6
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
19.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
20.	Robert Pellegrini	The United Illuminating Company	NPCC	1
21.	Saurabh Saksena	National Grid	NPCC	1
22.	Michael Schiavone	National Grid	NPCC	1
23.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
3.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jennifer Flandermeyer	KCPL	SPP	1, 3, 5, 6
2.	Scott Harris	KCPL	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Individual	Marc Gaudette	Dominion	X		X		X	X				
5.	Individual	Alison Mackellar - NERC Compliance Contact	Exelon Generation Company, LLC - Exelon Nuclear					X					
6.	Individual	Thomas Glock, Director Power Operations	Arizona Public Service Company	X		X		X		X	X		
7.	Individual	James H. Sorrels, Jr.	AEP	X		X		X	X				
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Individual	Edward Davis	Entergy Services, Inc	X		X		X	X				
10.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
11.	Individual	Bill Keagle	BGE	X									

1. Do you agree with the proposed implementation plan(s) generally provide a reasonable timeframe for implementing NERC's CIP Version 2 and Version 3 standards at nuclear power plants?

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council		No comment.
Arizona Public Service Company	No	The implementation plan draft requires implementation of cyber security plans, processes, and protocols and completion of related documentation for critical cyber assets (digital equipment) by no later than the first refueling outage at least 12 months beyond the FERC CIP effective date + 6 months. (So worst case 18 months after the effective date which may be May 2010). There is also a statement that "for multi-unit nuclear power plants, should separate outages be required to implement the plans, processes, and protocols for all units at the plant, the Responsible Entity shall indicate the need for separate outages in the self-certification report, including the time frame needed for implementation for each unit." As one of the newer nuclear plants, Palo Verde has a large number of digital systems. This will complicate the implementation process if only one outage is allowed per unit for implementation. In addition, outage scopes are determined based on the nuclear safety risk significance of work. Completion of the required work in one outage will either extend the duration of outages or result in the removal of nuclear safety significant work. The current implementation plan duration does not include consideration of mitigating aspects to critical cyber aspects (e.g. they are behind a data diode and have no other external connections). Determination of critical cyber asset vulnerabilities will require an outage to perform scans on equipment. In some cases, systems will have to be replaced or redesigned. This process can in some cases take two years (neglecting competing resource needs based on multiple systems needing changes at one time). Therefore, we request that the schedule for nuclear plants remain as the first refueling outage (more than 12 months after approval date) + 6 months for vulnerability assessment but that implementation completion for vulnerability assessment remediation be allowed to be performed based on a schedule that considers vulnerability mitigation measures (physical and electronic) such that the overall schedule does not exceed 60 months.
Response:		
Kansas City Power & Light	No	The Memorandum of Understanding does not contain a clear delineation of the systems, structures, and

Organization	Yes or No	Question 1 Comment
		components under NRC and NERC jurisdiction to render a judgment regarding an implementation time.
Response:		
AEP	Yes	
BGE	Yes	
Duke Energy	Yes	
Entergy Services, Inc	Yes	
South Carolina Electric and Gas	Yes	
Bonneville Power Administration	Yes	BPA would like to propose that Version 3 does not become effective until mid-2011.
Response:		
Dominion	Yes	Dominion considers the proposed implementation plan(s) generally provide a reasonable timeframe on the basis that the differences between CIP-002, Rev. 1 and CIP-002, Rev. 2 and Rev. 3 do not represent a significant change in the effort or schedule required for compliance.
Response:		
Exelon Generation Company, LLC - Exelon Nuclear	Yes	Generally the proposed implementation plan(s) provide a reasonable timeframe; however, Exelon Nuclear has concerns regarding the timeline for compliance regarding the Scope of Systems Determination. Understanding that the timeframes for implementing NERC's CIP Versions 2 and 3 are the same as the Version 1 proposed implementation plan, the timeline for compliance lists the later of the following:ï,§ The FERC Effective Date plus 18 months;ï,§ The Scope of Systems Determination plus 10 months; or,ï,§ Six months following the completion of the first refueling outage (if applicable) at least 18 months following the FERC Effective Date.With respect to the Scope of Systems Determination plus 10 months, in its January 19, 2010 filing, NERC provided responses that detailed an ongoing process with the NRC for developing an in-scope system list to distinguish systems, structures and components ("SSCs") that fall under NERC's jurisdiction from those that fall under the NRC's jurisdiction. In answer to the question "whether the exemption process will include (i) an application deadline and (ii) a deadline for determination of an exemption request," NERC stated that, "the determination of a licensees' scope of systems to be exempted from

Organization	Yes or No	Question 1 Comment
		compliance with the NERC CIP Reliability Standards must be made no later than R+8 months." NERCâ€™s response is somewhat problematic because it provides a specific time (R+8) assuming that its "Bright-Line management project plan" will be finalized prior to â€œR,â€ the date of FERC approval, and does not appear to allow any contingency for a delay in the Bright-Line determination. Without knowing for certain when NERC and the NRC will, in fact, finalize the Bright-Line determination, the formula R+8 months may not give licensees the full time intended. In addition, it is unclear how a licensee can know what systems to seek an exemption for prior to knowing what systems are subject to NERC jurisdiction under the Bright-Line determination.
Response:		

2. Does the proposed implementation plan language satisfy the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants?

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company		
Northeast Power Coordinating Council		No comment.
Exelon Generation Company, LLC - Exelon Nuclear	No	Exelon Nuclear agrees that the proposed implementation plan language satisfies the FERC directive relative to the implementation of CIP Versions 2 and 3. Exelon Nuclear does not see any documentation that satisfies the FERC directive that all future versions of the CIP Standards will address how owners and operators of nuclear power plants located in the United States will implement the revised CIP Standards. How does NERC intend to ensure that future modifications to CIP-002 through CIP-009 will be evaluated for impact against the current draft implementation plan(s) for nuclear generator owner/operators?
Response:		
Kansas City Power & Light	No	The Memorandum of Understanding does not contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction to render a judgment regarding FERC satisfaction.
Response:		
AEP	Yes	
BGE	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Dominion	Yes	No comments.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Draft Implementation Plan for Version 2 and Version 3 CIP Standards for Nuclear Power Plants (Project 2010-09)

The Cyber Security Order 706 Standard Drafting Team thanks all commenters who submitted comments on the draft implementation plan for version 2 and version 3 Critical Infrastructure Protection Standards for Nuclear Power Plants. These standards were posted for a 30-day public comment period from February 12, 2010 through March 15, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 11 sets of comments, including comments from 37 different people from over 20 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Most stakeholders who submitted comments agreed that the proposed implementation plans provide a reasonable timeframe for implementation of Version 2 and Version 3 CIP standards at nuclear power plants – and most stakeholders agreed that the proposed implementation plans meet the associated FERC directive.

Some stakeholders proposed extending the implementation timeframe beyond that proposed by the drafting team, but did not propose any 'new' reasons for this proposal. NERC is obligated, per FERC Order, to implement Version 2 and Version 3 CIP standards on the same schedule as Version 1, unless there is compelling justification to offer a different date. Absent any new information that would provide a compelling reason to extend the timeframe for implementation of the CIP standards, the team believes it appropriate to continue to align the Version 2 and Version 3 implementation plan dates for CIP-003 through CIP-009 on the same course as the schedule for implementation of the Version 1 implementation plan.

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 Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. Do you agree with the proposed implementation plan(s) generally provide a reasonable timeframe for implementing NERC's CIP Version 2 and Version 3 standards at nuclear power plants? 6

2. Does the proposed implementation plan language satisfy the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants? 10

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Sweeney	BPA, Transmission Sales	WECC	1

				1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	NA
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Brian L. Gooder		Ontario Power Generation Incorporated	NPCC			5						
12.	Kathleen Goodman		ISO - New England	NPCC			2						
13.	David Kiguel		Hydro One Networks Inc.	NPCC			1						
14.	Michael R. Lombardi		Northeast Utilities	NPCC			1						
15.	Randy MacDonald		New Brunswick System Operator	NPCC			2						
16.	Greg Mason		Dynegy Generation	NPCC			5						
17.	Bruce Metruck		New York Power Authority	NPCC			6						
18.	Chris Orzel		FPL Energy/NextEra Energy	NPCC			5						
19.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC			10						
20.	Robert Pellegrini		The United Illuminating Company	NPCC			1						
21.	Saurabh Saksena		National Grid	NPCC			1						
22.	Michael Schiavone		National Grid	NPCC			1						
23.	Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC			3						
3.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
	Additional Member		Additional Organization	Region			Segment Selection						
1.	Jennifer Flandermeyer		KCPL	SPP			1, 3, 5, 6						
2.	Scott Harris		KCPL	SPP			1, 3, 5, 6						
4.	Individual	Marc Gaudette	Dominion	X		X		X	X				
5.	Individual	Alison Mackellar - NERC Compliance Contact	Exelon Generation Company, LLC - Exelon Nuclear					X					
6.	Individual	Thomas Glock, Director Power Operations	Arizona Public Service Company	X		X		X		X	X		
7.	Individual	James H. Sorrels, Jr.	AEP	X		X		X	X				
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Individual	Edward Davis	Entergy Services, Inc	X		X		X	X				
10.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
11.	Individual	Bill Keagle	BGE	X									

1. Do you agree with the proposed implementation plan(s) generally provide a reasonable timeframe for implementing NERC's CIP Version 2 and Version 3 standards at nuclear power plants?

Summary Consideration: Most stakeholders who submitted comments agreed that the proposed implementation plans provide a reasonable timeframe for implementation of the CIP Version 2 and Version 3 standards at nuclear power plants and the drafting team did not make any changes to these plans.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council		No comment.
Arizona Public Service Company	No	The implementation plan draft requires implementation of cyber security plans, processes, and protocols and completion of related documentation for critical cyber assets (digital equipment) by no later than the first refueling outage at least 12 months beyond the FERC CIP effective date + 6 months. (So worst case 18 months after the effective date which may be May 2010). There is also a statement that "for multi-unit nuclear power plants, should separate outages be required to implement the plans, processes, and protocols for all units at the plant, the Responsible Entity shall indicate the need for separate outages in the self-certification report, including the time frame needed for implementation for each unit." As one of the newer nuclear plants, Palo Verde has a large number of digital systems. This will complicate the implementation process if only one outage is allowed per unit for implementation. In addition, outage scopes are determined based on the nuclear safety risk significance of work. Completion of the required work in one outage will either extend the duration of outages or result in the removal of nuclear safety significant work. The current implementation plan duration does not include consideration of mitigating aspects to critical cyber aspects (e.g. they are behind a data diode and have no other external connections). Determination of critical cyber asset vulnerabilities will require an outage to perform scans on equipment. In some cases, systems will have to be replaced or redesigned. This process can in some cases take two years (neglecting competing resource needs based on multiple systems needing changes at one time). Therefore, we request that the schedule for nuclear plants remain as the first refueling outage (more than 12 months after approval date) + 6 months for vulnerability assessment but that implementation completion for vulnerability assessment remediation be allowed to be performed based on a schedule that considers vulnerability mitigation measures (physical and electronic) such that the overall schedule does not exceed 60 months.
Response: The team appreciates your comments regarding the proposed implementation plans. Your concern is predicated upon the large number of digital systems at your plant, the existing mitigation strategies regarding those assets, and the impact on outage scheduling relative to the significance of the nuclear safety risk associated with the work. The team believes the proliferation of digital systems underscores the importance of ensuring critical infrastructure protection obligations that exist to protect and preserve the operation of not only the nuclear-related systems, but also for the reliable operation of the electric grid. Furthermore, the issues identified are not unique to the implementation of Version 2 and Version 3 of the		

Organization	Yes or No	Question 1 Comment
CIP standards, but are more generic to the structure of the implementation of the CIP standards at nuclear plants. These issues were discussed at length during the development of Version 1 of the implementation plan, just approved by FERC order on March 18, 2010, and supported by a significant number of your peers and by the electric utility industry at large. In addition, per that same FERC order, NERC is obliged to implement Version 2 and Version 3 on the same schedule as Version 1, unless there is compelling justification to offer a different date. Therefore, absent further support, the team believes it appropriate to continue to align the Version 2 and Version 3 implementation plan dates for CIP-003 through CIP-009 on the same course as the schedule for implementation of the Version 1 implementation plan. In this regard, the "R" date is now determined as November 18, 2011.		
Kansas City Power & Light	No	The Memorandum of Understanding does not contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction to render a judgment regarding an implementation time.
Response: NERC has committed in its January 19, 2010 filing to complete its scope of systems determination by R+8 or by November 18, 2010, or as FERC directed in its March 18, 2010 Order, NERC will notify FERC if it is unable to meet that deadline. However, in either circumstance, the nuclear plant owner/operator has the benefit of an "adjustable" implementation plan that is tied to the date of the scope of systems determination. Recall in the proposed implementation timeframe the inclusion of the S+10 months. This provides that if the scope of systems determination exceeds the dates contemplated, the implementation timeframe would accordingly be adjusted. Note that NERC intends, as outlined in its January 19, 2010 filing, to make the scope of systems determination using its Bright-Line Test in a two part process. NERC will conduct workshops outlining its test followed by the documentation process. These workshops are intended to facilitate the development of a Bright-Line Survey and to communicate expectations for licensees' completion of the survey. A preliminary Bright-Line Survey will be used as the starting point and will be presented at the workshops, subject to licensee modification based on their facility specific circumstances. The survey will be distributed following the workshop with expected completion in 30 days. NERC will verify the survey results beginning in June or July, 2010, utilizing site visits if necessary. A specific task-level project timeline was provided to accompany the NERC filing.		
AEP	Yes	
BGE	Yes	
Duke Energy	Yes	
Entergy Services, Inc	Yes	
South Carolina Electric and Gas	Yes	
Bonneville Power Administration	Yes	BPA would like to propose that Version 3 does not become effective until mid-2011.
Response: On current course as proposed herein and as discussed in the response to Arizona Public Service's comments, the current earliest		

Organization	Yes or No	Question 1 Comment
implementation date for CIP Version 2 and Version 3 would be November, 2011.		
Dominion	Yes	Dominion considers the proposed implementation plan(s) generally provide a reasonable timeframe on the basis that the differences between CIP-002, Rev. 1 and CIP-002, Rev. 2 and Rev. 3 do not represent a significant change in the effort or schedule required for compliance.
Response: Thank you for your comments.		
Exelon Generation Company, LLC - Exelon Nuclear	Yes	Generally the proposed implementation plan(s) provide a reasonable timeframe; however, Exelon Nuclear has concerns regarding the timeline for compliance regarding the Scope of Systems Determination. Understanding that the timeframes for implementing NERC's CIP Versions 2 and 3 are the same as the Version 1 proposed implementation plan, the timeline for compliance lists the later of the following:ï,§ The FERC Effective Date plus 18 months;ï,§ The Scope of Systems Determination plus 10 months; or,ï,§ Six months following the completion of the first refueling outage (if applicable) at least 18 months following the FERC Effective Date.With respect to the Scope of Systems Determination plus 10 months, in its January 19, 2010 filing, NERC provided responses that detailed an ongoing process with the NRC for developing an in-scope system list to distinguish systems, structures and components ("SSCs") that fall under NERC's jurisdiction from those that fall under the NRC's jurisdiction. In answer to the question "whether the exemption process will include (i) an application deadline and (ii) a deadline for determination of an exemption request," NERC stated that, "the determination of a licensees' scope of systems to be exempted from compliance with the NERC CIP Reliability Standards must be made no later than R+8 months." NERCâ€™s response is somewhat problematic because it provides a specific time (R+8) assuming that its "Bright-Line management project plan" will be finalized prior to â€œR,â€□ the date of FERC approval, and does not appear to allow any contingency for a delay in the Bright-Line determination. Without knowing for certain when NERC and the NRC will, in fact, finalize the Bright-Line determination, the formula R+8 months may not give licensees the full time intended. In addition, it is unclear how a licensee can know what systems to seek an exemption for prior to knowing what systems are subject to NERC jurisdiction under the Bright-Line determination.
Response: Thank you for your comments on the proposal. NERC has committed in its January 19, 2010 filing to complete its scope of systems determination by R+8 or by November 18, 2010, or as FERC directed in its March 18, 2010 Order, NERC will notify FERC if it is unable to meet that deadline. However, in either circumstance, the nuclear plant owner/operator has the benefit of an "adjustable" implementation plan that is tied to the date of the scope of systems determination. Recall in the proposed implementation timeframe the inclusion of the S+10 months. This provides that if the scope of systems determination exceeds the dates contemplated, the implementation timeframe would accordingly be adjusted. Note that NERC intends, as outlined in its January 19, 2010 filing, to make the scope of systems determination using its Bright-Line Test in a two part process. NERC will conduct workshops outlining its test followed by the documentation process. These workshops are intended to facilitate the development of a Bright-Line Survey and to communicate expectations for licensees' completion of the survey. A preliminary Bright-Line Survey will be used as the		

Organization	Yes or No	Question 1 Comment
starting point and will be presented at the workshops, subject to licensee modification based on their facility specific circumstances. The survey will be distributed following the workshop with expected completion in 30 days. NERC will verify the survey results beginning in June or July, 2010, utilizing site visits if necessary. A specific task-level project timeline was provided to accompany the NERC filing. In sum, licensees will have a clear sense of the Bright-Line determination in the 2nd quarter, 2010, with individualized licensee responses expected on the survey within 30 days after survey release.		

2. Does the proposed implementation plan language satisfy the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants?

Summary Consideration: Most stakeholders who submitted comments agreed that the proposed implementation plan language satisfies the FERC directive relative to the implementation of CIP Version 2 and future versions of the CIP standards at U.S. nuclear power plants and the drafting team did not make any changes to the plans.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council		No comment.
Exelon Generation Company, LLC - Exelon Nuclear	No	Exelon Nuclear agrees that the proposed implementation plan language satisfies the FERC directive relative to the implementation of CIP Versions 2 and 3. Exelon Nuclear does not see any documentation that satisfies the FERC directive that all future versions of the CIP Standards will address how owners and operators of nuclear power plants located in the United States will implement the revised CIP Standards. How does NERC intend to ensure that future modifications to CIP-002 through CIP-009 will be evaluated for impact against the current draft implementation plan(s) for nuclear generator owner/operators?
Response: Any future modifications to the CIP standards, including that for Version 4, will include implementation details specific for nuclear plants. To do so, NERC will solicit the support of representatives from the nuclear generating community as part of the standard development process.		
Kansas City Power & Light	No	The Memorandum of Understanding does not contain a clear delineation of the systems, structures, and components under NRC and NERC jurisdiction to render a judgment regarding FERC satisfaction.
Response: NERC has committed in its January 19, 2010 filing to complete its scope of systems determination by R+8 or by November 18, 2010, or as FERC directed in its March 18, 2010 Order, NERC will notify FERC if it is unable to meet that deadline. However, in either circumstance, the nuclear plant owner/operator has the benefit of an “adjustable” implementation plan that is tied to the date of the scope of systems determination. Recall in the proposed implementation timeframe the inclusion of the S+10 months. This provides that if the scope of systems determination exceeds the dates contemplated, the implementation timeframe would accordingly be adjusted. Note that NERC intends, as outlined in its January 19, 2010 filing, to make the scope of systems determination using its Bright-Line Test in a two part process. NERC will conduct workshops outlining its test followed by the documentation process. These workshops are intended to facilitate the development of a Bright-Line Survey and to communicate expectations for licensees’ completion of the survey. A preliminary Bright-Line Survey will be used as the starting point and will be presented at the workshops, subject to licensee modification based on their facility specific circumstances. The survey will be distributed following the workshop with expected completion in 30 days. NERC will verify the survey results beginning in June or July, 2010, utilizing site visits if necessary. A specific task-level		

Organization	Yes or No	Question 2 Comment
project timeline was provided to accompany the NERC filing.		
AEP	Yes	
BGE	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Entergy Services, Inc	Yes	
South Carolina Electric and Gas	Yes	
Dominion	Yes	No comments.

Standard Authorization Request Form

Title of Proposed Standard	Implementation Plans for US Nuclear Power Plant Owners and Operators for Version 2 and Version 3 CIP Standards (CIP-002 through CIP-009)
Request Date	January 19, 2010
SC Approval Date	January 20, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Gerry Adamski	☐	New Standard
Primary Contact	Gerry Adamski	x	Revision to existing Standard
Telephone Fax	609-524-0617 609-452-9550	☐	Withdrawal of existing Standard
E-mail	gerry.adamski@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) To add specificity to the implementation plans for the Version 2 and Version 3 CIP standards for US nuclear power plant owners and operators.
Industry Need (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.) NERC filed an implementation plan for the Version 1 CIP standards specific to US nuclear power plant owners and operators in accordance with FERC Order 706-B. However, FERC approved Version 2 of the standards to be implemented on April 1, 2010 and NERC filed Version 3 of the CIP standards in December. However, no specificity is included relative to the implementation of the Version 2 or Version 3 CIP standards for US nuclear power plant owners and operators. This project adds specificity with regard to the implementation timeline for US nuclear power plant owners and operators for the Version 2 and Version 3 CIP standards.
Brief Description (Provide a paragraph that describes the scope of this standard action.) Add the expected implementation timeline for Version 2 and Version 3 CIP standards for US nuclear power plant owners and operators.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Add the following language to the implementation plans for Version 2 and Version 3 of the CIP-002 through CIP-009 to specify the implementation timeline for US nuclear power plants:

Implementation of CIP Version 2 and 3 Standards for U.S Nuclear Power Plant Owners and Operators

On September 15, 2009, NERC filed for FERC approval an implementation plan for the CIP Version 1 standards (CIP-002-1 through CIP-009-1) for owners and operators of US nuclear power plants in compliance with Order 706-B. In the plan, compliance with the Version 1 standards is predicated upon the latter of the effective date of the order approving the implementation plan plus eighteen months; the determination of the scope of systems, structures, and components within the NERC and NRC jurisdictions plus ten months; or within six months following the completion of the first refueling outage beyond eighteen months from FERC approval of the implementation plan for those requirements requiring a refueling outage. Since that September 15, 2009 filing of the Version 1 implementation plan, FERC approved Version 2 of the NERC CIP standards on September 30, 2009 and NERC filed for FERC approval Version 3 CIP standards on December 29, 2009.

In its December 17, 2009 order on NERC's September 15, 2009 Version 1 implementation plan filing, FERC noted that the implementation timeline for the Version 2 CIP standards should be the same as the Implementation Plan for the Version 1 CIP standards. Consistent with this order and considering that only incremental modifications were made to Version 2 and Version 3 of the CIP standards relative to Version 1, compliance to Version 2 or Version 3 CIP-002 through CIP-009 standards (whichever is in effect at that time) for owners and operators of U.S. nuclear power plants will occur on the same schedule as the Version 1 CIP standards.

For example, if FERC approves the Version 1 implementation plan effective on May 1, 2010 and using the operative date for compliance to Version 1 standards as the FERC effective date of the order plus eighteen months, then compliance to the Version 1 standards would be required on November 1, 2011. However, since Version 1 will have been replaced by Version 2 and perhaps Version 3 by November, 2011, compliance to the Version 2 or Version 3 standards (whichever the current version is effective at that time) would therefore be required on November 1, 2011.

Using the hypothetical May 1, 2010 FERC effective date applied to a requirement linked to a refueling outage, compliance to the requirement would be required six months following the end of the first refueling outage that is beyond eighteen months from FERC approval of the implementation plan. In this case, the completion of the first refueling outage of the unit beyond November 1, 2011 would initiate the six month period. For purposes of this example, if the unit refueling outage occurred in the Spring, 2012 and ended on April 12, 2012, compliance with the requirement linked that outage would be required on October 12, 2012.

THIS WILL APPEAR IN A FOOTNOTE: These dates are provided as examples only and the FERC order effective date and compliance dates are hypothetical. Actual dates will be established based on FERC approval of the NERC Version 1 implementation schedule.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	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.
☐	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.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
X	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	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 box for all that apply.)*	
☐	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.
☐	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.
☐	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.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	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? *(Select 'yes' or 'no' from the drop-down box.)*
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
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

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Standards Announcement

Ballot Pool and Pre-ballot Window
April 19–May 19, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3

The revised implementation plans for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's critical infrastructure protection (CIP) standards are posted for a 30-day pre-ballot review **until 8 a.m. Eastern on May 19, 2010**.

Instructions

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-09_NUC_Imp_Plan_in@nerc.com

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

FERC recently approved NERC's filing of an implementation plan for the version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. The purpose of this project is to address the implementation timeline for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's CIP standards. Members of the original version 1 Cyber Security Drafting Team, which developed the version 1 implementation plan for U.S. nuclear power plant owners and operators, developed the language included in the revised implementation plans for the version 2 and 3 CIP standards.

Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at lauren.koller@nerc.net

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Standards Announcement

Initial Ballot Window Open

May 19–June 1, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3

An initial ballot window for the Nuclear Implementation Plans for CIP Version 2 and CIP Version 3 standards is now open **until 8 p.m. Eastern on June 1, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

FERC recently approved NERC's filing of an implementation plan for the version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. The purpose of this project is to address the implementation timeline for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's CIP standards. Members of the original version 1 Cyber Security Drafting Team, which developed the version 1 implementation plan for U.S. nuclear power plant owners and operators, developed the language included in the revised implementation plans for the version 2 and 3 CIP standards.

Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3
The initial ballot for the Nuclear Implementation Plans for CIP Version 2 and CIP Version 3 ended on June 1, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum:	84.83%
Approval:	90.83%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
FERC recently approved NERC's filing of an Implementation Plan for the Version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. The purpose of this project is to address the implementation timeline for U.S. nuclear power plant owners and operators for Versions 2 and 3 of NERC's CIP Reliability Standards. Members of the original Version 1 Cyber Security Drafting Team, which developed the Version 1 Implementation Plan for U.S. nuclear power plant owners and operators, developed the language included in the revised Implementation Plans for the Version 2 and 3 CIP standards.

More information is available on the project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria
Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

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Ballot Results	
Ballot Name:	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in
Ballot Period:	5/19/2010 - 6/1/2010
Ballot Type:	Initial
Total # Votes:	179
Total Ballot Pool:	211
Quorum:	84.83 % The Quorum has been reached
Weighted Segment Vote:	90.83 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	51	1	28	0.824	6	0.176	11	6
2 - Segment 2.	8	0.2	2	0.2	0	0	5	1
3 - Segment 3.	50	1	28	0.903	3	0.097	12	7
4 - Segment 4.	11	0.6	5	0.5	1	0.1	5	0
5 - Segment 5.	43	1	21	0.955	1	0.045	10	11
6 - Segment 6.	31	1	19	0.95	1	0.05	5	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.6	5	0.5	1	0.1	0	1
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	8	0.6	6	0.6	0	0	2	0
Totals	**211**	**6.2**	**116**	**5.632**	**13**	**0.568**	**50**	**32**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Abstain	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Abstain	
1	Lake Worth Utilities	Walt Gill		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	
1	PacifiCorp	Mark Sampson	Abstain	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Abstain	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Abstain	
1	Westar Energy	Allen Klassen	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	California ISO	Timothy VanBlaricom	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Abstain	
3	City of Clewiston	Lynne Mila	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Abstain	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis		
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Abstain	
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	MEAG Power	Steven Grego	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson		
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Salt River Project	John T. Underhill	Negative	View
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	City of Clewiston	Kevin McCarthy	Abstain	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Kansas Electric Power Cooperative, Inc.	John Payne	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Cleco Power LLC	Grant Bryant		
5	Conectiv Energy Supply, Inc.	Kara Dundas	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Environmental Systems Corporation	Jennifer Bower	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann		
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	

5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	Tampa Electric Co.	RJames Rocha		
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Abstain	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	

10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan — 05/19/10 — 06/01/10

Summary Consideration:
During the initial ballot, NERC received 9 sets of comments from 12 individuals representing 5 of the 10 registered ballot body segments. These comments centered on two main themes: that the impact of these proposed standards cannot be fully understood without the bright-line determination of the scope of systems, structures, and facilities for each plant; and that NERC should consider granting a waiver of compliance to Versions 2 and 3 of the current CIP standards with the understanding that Version 4 of the CIP standards would be implemented on a schedule as aggressive as contained in this proposal.

Regarding the bright-line determination process, as outlined in its January 19, 2010 compliance filing to FERC, NERC committed to completing the bright-line determination within eight months following the approval of the proposed implementation plan. FERC granted such approval on March 18, 2010. As such, NERC is on target for completing this effort by the October/November 2010 timeframe. To this end, NERC engaged representatives from nuclear power plants on preliminary drafts of the bright-line survey forms and, as a follow-up, conducted four workshops in which each of the US nuclear power plants was represented. Individual nuclear power plant surveys were distributed in June and responses are due back in July with NERC and the NRC collaboratively finalizing the systems scope for each plant by the fall milestone target. Given this engagement, greater certainty in the scope of impacted systems has been provided and will be further finalized in the upcoming months leading to the completion of the effort in the fall.

With regard to the discussion on CIP Version 4, it is premature to consider the impacts of Version 4 as the standards remain to be finalized, approved by stakeholders, accepted by the NERC Board, filed for regulatory approval, and approved by FERC and other applicable governmental authorities. Additionally, the implementation of the CIP Version 4 standards will take place on its own timeline that may be years in the future, perpetuating a gap in cyber coverage if a waiver were permitted. Members of the nuclear community have been added to the Version 4 drafting team for the express purpose of ensuring the implementation plan is appropriate. Therefore, conditioning approval of this implementation plan on those CIP Version 4 activities is not useful at this point in time. The CIP Version 4 drafting team is mindful of the transition from the existing versions of the standards to the proposed Version 4 standards with the goal to the extent possible to preserve the existing foundational work and build upon it in Version 4. Furthermore, a request for waiver of CIP Versions 2 or 3 would not alleviate the need to implement Version 1 of the CIP standards currently approved for implementation.

If you feel that the drafting team overlooked your comments, 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 Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Thomas R. Glock	Arizona Public Service Co.	3	Negative	APS would like NERC to consider the option of providing a waiver on implementation of CIPS 02 through 09 with the caveat that CIPS 10 and 11 (Revision 4) would be implemented under a schedule as rigorous as was required for CIPS 02 - 09 (i.e. the 18 month clock would begin on the approval date of CIP 10 and 11 (Revision 4) APS believes that such a move would allow implementation of a more cohesive and comprehensive cyber security program as well as ensuring that work done by the industry in support of NERC CIP standards implementation was performed in accordance with the future direction of NERC.
Response: **Thank you for your comments. However, it is premature to consider the impacts of Version 4 as the standards remain to be finalized, approved by stakeholders, accepted by the NERC Board, filed for regulatory approval, and approved by FERC and other applicable governmental authorities. Additionally, the implementation of the CIP Version 4 standards will take place on its own timeline that may be years in the future, perpetuating a gap in cyber coverage if a waiver were permitted. Members of the nuclear community have been added to the Version 4 drafting team for the express purpose of ensuring the implementation plan is appropriate. Therefore, conditioning approval of this implementation plan on those CIP Version 4 activities is not useful at this point in time. The CIP Version 4 drafting team is mindful of the transition from the existing versions of the standards to the proposed Version 4 standards with the goal to the extent possible to preserve the existing foundational work and build upon it in Version 4. Furthermore, a request for waiver of CIP Versions 2 or 3 would not alleviate the need to implement Version 1 of the CIP standards currently approved for implementation.**				
John Payne	Kansas Electric Power Cooperative, Inc.	4	Negative	Judging the validity of an implementation schedule is difficult when the scope of compliance is not know. The Bright-Line should be defined first.
Response: **Thank you for your comments. As outlined in its January 19, 2010 compliance filing to FERC, NERC committed to completing the bright-line determination within eight months following the approval of the proposed implementation plan. FERC granted such approval on March 18, 2010. As such, NERC is on target for completing this effort by the October/November 2010 timeframe. To this end, NERC engaged representatives from nuclear power plants on preliminary drafts of the bright-line survey forms and, as a follow-up, conducted four workshops in which each of the US nuclear power plants was represented. Individual nuclear power plant surveys were distributed in June and responses are due back in July with NERC and the NRC collaboratively finalizing the systems scope for each plant by the fall milestone target. Given this engagement, greater certainty in the scope of impacted systems has been provided and will be further finalized in the upcoming months leading to the completion of the effort in the fall of 2010.**				
John T. Underhill	Salt River Project	3	Negative	Palo Verde Nuclear Generating Station recognizes the importance of Cyber Security and is aggressively working towards implementation of the NERC CIPS 02 through 09, Revision 3. During our review of CIPS 10 and 11 (Revision 4) it became clear that the requirements in CIPS 10 and 11 were 1) noticeably different than those in 02 through 09, Revision 3 and, 2) much more in line with the NIST Cyber Security standards (and therefore similar to the NRC's Cyber Security requirements in 10CFR 73.54). Would NERC consider the option of providing a waiver on implementation of CIPS 02 through 09 with the caveat that CIPS 10 and 11 (Revision 4) would be implemented under a schedule as rigorous as was required for CIPS 02 - 09 (i.e. the 18 month clock would begin on the approval date of CIP 10 and 11 (Revision 4)? PVNGS believes that such a move would allow implementation of a more cohesive and comprehensive cyber security program as well as ensuring that work done by the industry in support of NERC CIPS

Voter	Entity	Segment	Vote	Comment
				implementation was performed in accordance with the future direction of NERC.?
Response: **Thank you for your comments. However, it is premature to consider the impacts of Version 4 as the standards remain to be finalized, approved by stakeholders, accepted by the NERC Board, filed for regulatory approval, and approved by FERC and other applicable governmental authorities. Additionally, the implementation of the CIP Version 4 standards will take place on its own timeline that may be years in the future, perpetuating a gap in cyber coverage if a waiver were permitted. Members of the nuclear community have been added to the Version 4 drafting team for the express purpose of ensuring the implementation plan is appropriate. Therefore, conditioning approval of this implementation plan on those CIP Version 4 activities is not useful at this point in time. The CIP Version 4 drafting team is mindful of the transition from the existing versions of the standards to the proposed Version 4 standards with the goal to the extent possible to preserve the existing foundational work and build upon it in Version 4. Furthermore, a request for waiver of CIP Versions 2 or 3 would not alleviate the need to implement Version 1 of the CIP standards currently approved for implementation.**				
Robert D Smith	Arizona Public Service Co.	1	Negative	PVNGS recognizes the importance of Cyber Security and is aggressively working towards implementation of the NERC CIPS 02 through 09, Revision 3. During our review of CIPS 10 and 11 (Revision 4) it became clear that the requirements in CIPS 10 and 11 were 1) noticeably different than those in 02 through 09, Revision 3 and, 2) much more in line with the NIST Cyber Security standards (and therefore similar to the NRC's Cyber Security requirements in 10CFR 73.54). Would NERC consider the option of providing a waiver on implementation of CIPS 02 through 09 with the caveat that CIPS 10 and 11 (Revision 4) would be implemented under a schedule as rigorous as was required for CIPS 02 - 09 (i.e. the 18 month clock would begin on the approval date of CIP 10 and 11 (Revision 4)? PVNGS believes that such a move would allow implementation of a more cohesive and comprehensive cyber security program as well as ensuring that work done by the industry in support of NERC CIPS implementation was performed in accordance with the future direction of NERC.
Response: **Thank you for your comments. However, it is premature to consider the impacts of Version 4 as the standards remain to be finalized, approved by stakeholders, accepted by the NERC Board, filed for regulatory approval, and approved by FERC and other applicable governmental authorities. Additionally, the implementation of the CIP Version 4 standards will take place on its own timeline that may be years in the future, perpetuating a gap in cyber coverage if a waiver were permitted. Members of the nuclear community have been added to the Version 4 drafting team for the express purpose of ensuring the implementation plan is appropriate. Therefore, conditioning approval of this implementation plan on those CIP Version 4 activities is not useful at this point in time. The CIP Version 4 drafting team is mindful of the transition from the existing versions of the standards to the proposed Version 4 standards with the goal to the extent possible to preserve the existing foundational work and build upon it in Version 4. Furthermore, a request for waiver of CIP Versions 2 or 3 would not alleviate the need to implement Version 1 of the CIP standards currently approved for implementation.**				
Robert Kondziolka	Salt River Project	1	Negative	PVNGS recognizes the importance of Cyber Security and is aggressively working towards implementation of the NERC CIPS 02 through 09, Revision 3. During their review of CIPS 10 and 11 (Revision 4) it became clear that the requirements in CIPS 10 and 11 were 1) noticeably different than those in 02 through 09, Revision 3 and, 2) much more in line with the NIST Cyber Security standards (and therefore similar to the NRC's Cyber Security requirements in 10CFR 73.54). NERC should consider the option of providing a waiver on implementation of CIPS 02 through 09 with the caveat that CIPS 10 and 11 (Revision 4) would be implemented under a

<table>
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<tr><td></td><td></td><td></td><td></td><td>schedule as rigorous as was required for CIPS 02 - 09 (i.e. the 18 month clock would begin on the approval date of CIP 10 and 11 (Revision 4). PVNGS believes that such a move would allow implementation of a more cohesive and comprehensive cyber security program as well as ensuring that work done by the industry in support of NERC CIPS implementation was performed in accordance with the future direction of NERC.?</td></tr>
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<tr><td>Charles Locke</td><td>Kansas City Power & Light Co.</td><td>3</td><td>Negative</td><td rowspan="2">There is sufficient uncertainty with the "Bright Line" outcome that it is premature to vote on the implementation plan proposed here until the potential systems and components that could come under the CIP Standards are known from the "Bright Line" efforts. It is recommended to postpone voting on these proposed implementation plans until the outcome of the Bright Line results are known.</td></tr>
<tr><td>Thomas Saitta</td><td>Kansas City Power & Light Co.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. As outlined in its January 19, 2010 compliance filing to FERC, NERC committed to completing the bright-line determination within eight months following the approval of the proposed implementation plan. FERC granted such approval on March 18, 2010. As such, NERC is on target for completing this effort by the October/November 2010 timeframe. In early February, NERC made an informal solicitation of comments on an initial draft of the bright-line survey that was updated and presented to representatives of each of the 104 US nuclear plants at four workshops in late spring. Based on these activities, each nuclear power plant should fully understand the general scope of systems that are to be included for purposes of the CIP standards. Individual plant surveys were distributed in mid-June with plant responses due by the mid- to late July timeframe. NERC and the NRC have committed to reviewing these submissions beginning in August and plan to finalize the scope of systems by the previously identified milestone date. Therefore, greater certainty in the scope of impacted systems has been provided and will be further refined in the upcoming months leading to the completion of the effort in the fall.</td></tr>
<tr><td>Michael Gammon</td><td>Kansas City Power & Light Co.</td><td>1</td><td>Negative</td><td>There is sufficient uncertainty with the "Bright Line" survey outcome that it is premature to vote on the implementation plan proposed here until the potential systems and components that could come under the CIP Standards are known from the "Bright Line" efforts. It is recommended to postpone voting on these proposed implementation plans until the outcome of the Bright Line results are known.</td></tr>
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</table>

Voter	Entity	Segment	Vote	Comment
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Allen Klassen	Westar Energy	1	Negative	This is asking for approval of an implementation plan prior to us having a full understanding of the equipment that will be in scope.
Response: **Thank you for your comments. As outlined in its January 19, 2010 compliance filing to FERC, NERC committed to completing the bright-line determination within eight months following the approval of the proposed implementation plan. FERC granted such approval on March 18, 2010. As such, NERC is on target for completing this effort by the October/November 2010 timeframe. In early February, NERC made an informal solicitation of comments on an initial draft of the bright-line survey that was updated and presented to representatives of each of the 104 US nuclear plants at four workshops in late spring. Based on these activities, each nuclear power plant should fully understand the general scope of systems that are to be included for purposes of the CIP standards. Individual plant surveys were distributed in mid-June with plant responses due by the mid- to late July timeframe. NERC and the NRC have committed to reviewing these submissions beginning in August and plan to finalize the scope of systems by the previously identified milestone date. Therefore, greater certainty in the scope of impacted systems has been provided and will be further refined in the upcoming months leading to the completion of the effort in the fall of 2010.**				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Response: **Thank you for your affirmative vote.**				
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Affirmative	PSE&G is voting affirmatively for the implementation plans. However, PSE&G suggests that the drafting team consider adopting the same approach as the NRC for similar activity. Identification of the plant systems and components, performance of assessments against CIP requirements, evaluation of remediation alternatives, engineering design changes associated with remediation activities along with the planning, scheduling, and implementation of the changes required for CIP compliance in conjunction with the development of a complete CIP compliance program with supporting procedures and training is a significant level of effort requiring multiple years to complete. As a point of reference, most nuclear facility licensees are seeking 3 or more years from the Nuclear Regulatory Commission (NRC) to complete all the aforementioned activities associated with protecting the plant communication systems & network components within the scope of NRC's 10CFR73.54 Rule. We feel the CIP V2 and V3 implementation schedules may not allow adequate time to properly complete all of the aforementioned activities and feel the current implementation schedules as presently worded should be simplified and suggest instead the implementation schedule modified to be 3 years after the FERC effective date.
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Affirmative	
David Murray	PSEG Power LLC	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. The proposed implementation plan was developed by a team that included representatives from the nuclear power plant community and determined to be appropriate for implementation. The structure of the plan is identical to that agreed upon and approved for Version 1 of the CIP standards. Members of the nuclear community are involved in the drafting of the Version 4 of the CIP standards during which it would be appropriate consider the alternate approach you identify in your comments. In this regard, these comments will be forwarded to the Version 4 team.				

Standards Announcement

Recirculation Ballot Window Open
June 22–July 2, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3
A recirculation ballot window for Nuclear Implementation Plans for CIP Version 2 and CIP Version 3 standards is now open **until 8 p.m. Eastern on July 2, 2010.**

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Process
The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Next Steps
Voting results will be posted and announced after the ballot window closes.

Project Background
FERC recently approved NERC's filing of an implementation plan for the version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. The purpose of this project is to address the implementation timeline for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's CIP standards. Members of the original version 1 Cyber Security Drafting Team, which developed the version 1 implementation plan for U.S. nuclear power plant owners and operators, developed the language included in the revised implementation plans for the version 2 and 3 CIP standards.

Project page:
http://www.nerc.com/filez/standards/Cyber_Security_Order706B_Nuclear_Plant_Implementation_Plan.html

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Final Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3 Standards

The recirculation ballot for the Nuclear Implementation Plans for CIP Version 2 and CIP Version 3 standards ended July 2, 2010.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 89.10%
Approval: 87.24%

The ballot pool approved the implementation plan. Ballot criteria details are listed at the end of the announcement.

Next Steps

The implementation plans will be submitted to the NERC Board of Trustees for approval.

Project Background

FERC recently approved NERC's filing of an implementation plan for the version 1 CIP standards, CIP-002-1 through CIP-009-1, specific to U.S. nuclear power plant owners and operators in accordance with FERC Order 706-B. The purpose of this project is to address the implementation timeline for U.S. nuclear power plant owners and operators for versions 2 and 3 of NERC's CIP standards. Members of the original version 1 Cyber Security Drafting Team, which developed the version 1 implementation plan for U.S. nuclear power plant owners and operators, developed the language included in the revised implementation plans for the version 2 and 3 CIP standards.

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Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

Ballot Results	
Ballot Name:	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc
Ballot Period:	6/22/2010 - 7/2/2010
Ballot Type:	recirculation
Total # Votes:	188
Total Ballot Pool:	211
Quorum:	**89.10 % The Quorum has been reached**
Weighted Segment Vote:	87.24 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	51	1	29	0.853	5	0.147	15	2
2 - Segment 2.	8	0.2	2	0.2	0	0	6	0
3 - Segment 3.	50	1	27	0.844	5	0.156	12	6
4 - Segment 4.	11	0.6	5	0.5	1	0.1	5	0
5 - Segment 5.	43	1	21	0.875	3	0.125	10	9
6 - Segment 6.	31	1	17	0.85	3	0.15	6	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.6	5	0.5	1	0.1	0	1
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	8	0.5	5	0.5	0	0	3	0
Totals	**211**	**6.1**	**113**	**5.322**	**18**	**0.778**	**57**	**23**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Abstain	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Abstain	
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Abstain	
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	
1	PacifiCorp	Mark Sampson	Abstain	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Abstain	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Abstain	
1	Westar Energy	Allen Klassen	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	California ISO	Timothy VanBlaricom	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Abstain	
3	City of Clewiston	Lynne Mila	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Abstain	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Abstain	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Abstain	
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	MEAG Power	Steven Grego	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David T. Anderson		
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Abstain	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Salt River Project	John T. Underhill	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	City of Clewiston	Kevin McCarthy	Abstain	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Kansas Electric Power Cooperative, Inc.	John Payne	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Cleco Power LLC	Grant Bryant		
5	Conectiv Energy Supply, Inc.	Kara Dundas	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Environmental Systems Corporation	Jennifer Bower	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	

5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	Tampa Electric Co.	RJames Rocha		
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Abstain	
6	Progress Energy	James Eckelkamp	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	

10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Account Log-In/Register

Exhibit C

Standard Drafting Team Roster

Order 706B Nuclear Implementation Plan Standard Drafting Team

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