Consideration of Comments

Real-Time Transmission Operations — Project 2007-03

The Real-Time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 5th draft and initial ballot of the standards for Real-Time Operations (Project 2007-03). The standard and associated documents were posted for a 45-day public comment period from April 26, 2011 through June 9, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special Electronic Comment Form. There were 44 sets of comments, including comments from approximately 156 different people from approximately 97 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

TOP-001-2:

- Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- Revised Requirement R1 to note that a Reliability Directive should be identified as such
- Deleted 'upon recognition' from Requirement R2
- Deleted 'all other' from Requirement R3
- Added Reliability Coordinator to Requirement R5
- Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- Made a semantic change for clarity to Measure M2
- Changed the Time Horizons for Requirements R3, R5, and R8
- VSLs for Requirements R3, R5, and R6 were changed to move away from percentages

- The language for the VSLs in Requirements R2, R6, & R8 was clarified
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term "NERC" as a modifier of "registered entities" in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirmeent R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."

Minority opinions expressed at this point include:

- There is still some debate as to what is meant by internal area reliability. The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator.
- Questions arose about the role of the Balancing Authority in the actions described in the revised TOP standards. The SDT has clearly defined each element of responsibility that was previously defined for the Balancing Authority in the existing TOP standards and how it was handled in the revised TOP standards. The SDT does not believe that any gaps have been created by the revisions.
- Some commenters continue to debate the treatment of internal area reliability related SOLs in the same manner as IROLs.

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 of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@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. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 12

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 57

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 69

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments................................. 85

5. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here. 109

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Rodriquez	Entegra Power	SERC	5
2.	Bill Autrey	Alabama Power	SERC	1, 3, 5
3.	Jake Miller	Dynegy	SERC	5, 6
4.	Scott Brame	NCEMCS	SERC	1, 3, 5, 9
5.	Jeff Harrison	AECI	SERC	1, 3, 5
6.	Mike Hardy	Southern	SERC	1, 3, 5
7.	Robert Thomasson	BREC	SERC	1, 3, 5, 9
8.	Chris Bolick	AECI	SERC	1, 3, 5
9.	Shardra Scott	Gulf Power	SERC	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10. John Troha		SERC	SERC 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.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	1
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Connie Lowe	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1
2.	Louis Slade		RFC	5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

3.	Mike Garton		MRO	5, 6
4.	Michael Gildea		NPCC	5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Patricia Robertson	BC Hydro	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vinnakota Venkataramakrishnan	BC Hydro	WECC	2
2.	Pat G Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5
4.	Daniel W O'Hearn	Powerex Corp.	WECC	6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Mikhail Falkovich	Public Service Enterprise Group LLC	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clint Bogan		NPCC	5, 6
2.	Ken Brown		RFC	1
3.	Jeffery Mueller		RFC	3
4.	Peter Dolan		RFC	6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Jim Keller	Wisconsin Electric Power Company			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Linda Horn	Wisconsin Electric Power Company	RFC	5
2.	Tony Jankowski	Wisconsin Electric Power Company	RFC	4

				1	2	3	4	5	6	7	8	9	10
7.	Group	Joe O'Brien	NIPSCO	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Largura	NIPSCO	RFC	1
2.	Bill Sedoris	NIPSCO	RFC	3
3.	Bill Thompson	NIPSCO	RFC	5
4.	Joe O'Brien			6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tedd Snodgrass	BPA, Transmission Dispatch	WECC	1
2.	Tim Loepker	BPA, Transmission Dispatch	WECC	1
3.	John Anasis	BPA, Transmission Technical Operations	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Steve Larson		BPA, Legal Office	WECC 1, 3, 5, 6										
9.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Cathy Bretz	IID	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Reed	FE	RFC	1
2.	Ralph Cannon	FE	RFC	1
3.	Ken Dresner	FE	RFC	5
4.	Brian Orians	FE	RFC	5
5.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
6.	Rusty Loy	FE	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5

14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6								
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5								
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6								
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Group	Brent Ingebrigtson	LG&E and KU Energy			X							
No additional members listed.													
13.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Greg Campoli	NY ISO	NPCC	2
4.	Mike Falvo	IESO	NPCC	2
5.	Matt Goldberg	ISO NE	NPCC	2
6.	Kathleen Goodman	ISO NE	NPCC	2
7.	Ben Li	IESO	NPCC	2
8.	Steve Myers	ERCOT	ERCOT	2
9.	Bill Phillips	MISO	RFC	2
10.	Mark Thompson	AESO	WECC	2
11.	Mark Westendorf	MISO	RFC	2
12.	Charles Yeung	SPP	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	Lower Mount Bethel Energy, LLC	RFC	5
2.	PPL Brunner Island, LLC	RFC	5
3.	PPL Holtwood, LLC	RFC	5
4.	PPL Martins Creek, LLC	RFC	5
5.	PPL Montour, LLC	RFC	5
6.	PPL Montana, LLC	WECC	5
7.	PPL EnergyPlus, LLC	MRO	6
8.	PPL EnergyPlus, LLC	NPCC	6
9.	PPL EnergyPlus, LLC	RFC	6
10.	PPL EnergyPlus, LLC	SERC	6
11.	PPL EnergyPlus, LLC	SPP	6
12.	PPL EnergyPlus, LLC	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Individual	Jeff Longshore	Luminant Energy						X				
17.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
18.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
19.	Individual	Mike Laney	Luminant Power					X					
20.	Individual	Antonio Grayson	Southern Company	X		X							
21.	Individual	Chang Choi	City of Tacoma or Tacoma Public Utilities	X		X	X	X	X				
22.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				
25.	Individual	Larry Grimm	Texas Reliability Entity										X
26.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
27.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	Rex Roehl	Indeck Energy Services					X					
30.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
32.	Individual	David Thorne	Pepco Holdings Inc	X		X							
33.	Individual	Kirit Shah	Ameren	X		X		X	X				
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Denise Lietz	Puget Sound Energy	X		X		X					
36.	Individual	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				
37.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
38.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
39.	Individual	Bill Keagle	BGE	X									
40.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
41.	Individual	Michael Moltane	ITC	X									
42.	Individual	Kathleen Goodman	ISO New England Inc.		X								
43.	Individual	Brenda Pulis	Oncor Electric Delivery	X									
44.	Individual	Michael Falvo	Independent Electricity System Operator		X								

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: In response to comments, Requirements R1, R2, R3, R5, R6, R9, and R11 were changed, along with conforming changes to the respective measures. Measure M2 was also changed in response to a specific comment. Conforming changes were made to the respective VSLs. These changes mitigated apparent double jeopardy, clarified Reliability Directives, and removed references to 30 minutes as the time limit for correcting the exceedence of an SOL.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s $T_{v.}$, or of an SOL identified in Requirement R8.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

M5. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Organization	Yes or No	Question 1 Comment
Duke Energy Duke Energy Carolina	No	We disagree with the revised definition of Reliability Directive. The phrase “or expected” creates compliance uncertainty and should be struck. o R8 - We have made this comment before and continue to strongly believe that the phrase “supporting its internal area reliability” should be replaced with the phrase “having an Adverse Reliability Impact”. In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified

Organization	Yes or No	Question 1 Comment
		as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very clearly doesn’t meet the guidelines. o R9 - The VRF has been changed from “High” to “Medium”. Consistent with our previous comment on R8, we question how the drafting team was able to justify a “High” or “Medium” VRF. It very clearly doesn’t meet the guidelines. o R11 - Including the SOLs identified in R8 in this requirement effectively makes those SOLs equivalent to an IROL for mitigation purposes. Consistent with our comments above on R8 and R9, our concern is that under this approach all equipment ratings could potentially become SOLs subject to the same mitigation as IROLs.

Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for recirculation ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.

R8: The SDT reminds the commenter that the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase ‘internal area reliability’ was left undefined to encompass each of these unique challenges. No change made.

R9: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirement R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made.

R11: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1)We do not agree with the definition of "Reliability Directive". The phrase "expected" Emergency creates uncertainty and will create controversy. We suggest to remove the "actual or expected" phrase, and instead add "... condition or situation that threatens the reliability of the Bulk Electric System and is likely to lead to cascading, separation, islanding, ..." after emergency consistent with the intent of the FPA and NERC Standards. (2) In R2, the SDT uses the adjective "identified" which, in the Compliance and Enforcement arena, unfortunately may imply a new and different type of Directive (an "identified Reliability Directive"). We assume the SDT meant to imply with the word "identified", that the TOP would let know the receiving party explicitly that the communication that they were receiving was in fact a Reliability Directive and not just some other form of operating communication. IF that is the case, we suggest that the SDT simply state that fact as follows, "A Directive issued by a TOP which is referred to in the ensuing 3-way communication with the recipient of that Directive using the specific words Reliability Directive". (3)In R6, we have concerns with the Generator Operator having to "notify negatively impacted interconnected NERC registered entities of planned outages of telemetry..." etc. This is too broad for a GOP to be lumped in with the TOP and BA, since most GOPs do not have the knowledge if these planned outages would negatively affect other NERC entities. We believe that R6 should apply to TOP and BA, and maybe have R6.1 that requires the GOP to notify their specific TOP and BA of planned outages of telemetry, control equipment, and communication channels which in turn would generate communication from the host TOP and BA to others so affected. (4) In R8, what is meant by "internal" area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited. (5) R11 refers to R8 and SOL. Is it the intent of the SDT to consider SOL effectively the same as IROL for purpose of this requirement?
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.		

Organization	Yes or No	Question 1 Comment
The wording of Requirement R1 has been altered to add the term “identified” which will now tie to Requirement R2. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. The SDT reminds the commenter the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase ‘internal area reliability’ was left undefined to encompass each of these unique challenges. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
Occidental Chemical	Ballot Comment	1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 0 Yes 1 No Comments:Ingleside Cogeneration LP agrees with most of the concepts and language the SDT is driving to in TOP-001-2. However, there are two items which we believe require further exploration before we can vote in favor of the standard. First, requirements R1 and R2 present a double-jeopardy to a GOP if a front line operator does not inform the TOP of an inability to comply with an identified Reliability Directive that violate safety, equipment, regulatory, or statutory requirements. The requirements can be modified as shown below to capture the same intent without having two high VRF assessments for the same incident. R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability

Organization	Yes or No	Question 1 Comment
		Directive issued by its Transmission Operator, [delete: unless the respective entity informs its Transmission Operator that - end delete] such actions would violate safety, equipment, regulatory, or statutory requirements. R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. Second, the concept of moving all operational data requirements - including outage notifications - to a single standard (TOP-003-1) is a useful consolidation of many similar requirements. We believe that it can be logically extended to include the notification of telemetry and control equipment outages which now fall under R6. Furthermore, TOP-003-1 requires the creation of a data specification and reporting criteria - which is far more specific than the open-ended language used in R6. 2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: From a GO/GOP perspective, Ingleside Cogeneration LP agrees that a significant amount of redundancy has been removed by consolidating requirements to coordinate day-of, next-day, and seasonal operations under TOP-003. The same is true of the requirement to perform real and reactive capacity validations - which are addressed in the MOD standards. 3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: Ingleside Cogeneration LP strongly supports the consolidation of TOP and BA operations data requirements into a single specification. In addition, the Project Team has correctly recognized that web-based portals and similar applications are becoming more prevalent - and should be encouraged as an effective means to distribute operations information.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Colorado Springs Utilities	No	Colorado Springs Utilities appreciates the opportunity to comment on this draft and the changes made to this standard. The following comments are specific to requirements R3,R4, R8/R10,R9, & R11. R3. By changing "of" to "by" there is now no object to the verb "inform". Suggested language: "Each Transmission Operator shall share its assessment of its Operational Planning Analysis with its Reliability Coordinator, and all other Transmission Operators that are known or expected to be affected, based on that assessment, by actual and anticipated Emergencies." R4. Colorado Springs Utilities agrees with those who have commented on previous drafts that the language strongly implies that the TOP rendering assistance is obligated to ensure the entity receiving assistance has implemented "comparable emergency procedures." We recommend the requirement be rewritten: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Transmission Operator requested to provide such assistance may require that the requesting entity first implement its own comparable emergency procedures.” R8/R10. SOLs, which are not IROLs, by definition, do not impact interconnection reliability and should be the responsibility of the TOP, not the RC, and therefore should not require being reported to nor monitored by the

Organization	Yes or No	Question 1 Comment
		RC. R9. Does R9, as written, prevent the TOP from employing the option to permit equipment life reduction to avoid load shed? R11. Despite the SDT's clarifying comments provided during previous comment periods, this requirement continues to appear duplicative to R7 & R9 and seems to provide opportunity for double jeopardy in the event of non-compliance with one of those requirements. We suggest R11 be eliminated. If exceeding the SOL or IROL is remedied and restored within the required time frame, then the operator or the system has taken appropriate mitigating action.
Response: The suggested language for Requirement R3 was not accepted. This was the only comment on Requirement R3 from the ballot pool and the wording change is a style suggestion, not an improvement to reliability. No change made. The suggested language for Requirement R4 was not accepted. The meaning of "...provided that the requesting entity has implemented its comparable emergency procedures,…." is clear and unambiguous. No change made. Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards. The change has not been accepted. R9: This requirement is confined to that subset of SOLs that are important to internal area reliability as identified in the Operational Planning Analysis. It does not prohibit the adoption of an emergency rating that sacrifices equipment life. FAC-008-1 requires each Transmission Owner and Generator Owner to have a methodology for Facility Ratings that includes (R1.3): "Consideration of the following: R1.3.1. Ratings provided by equipment manufacturers. R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards). R1.3.3. Ambient conditions. R1.3.4. Operating limitations. R1.3.5. Other assumptions." Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Cowlitz County PUD	No	Cowlitz respectfully disagrees with the SDT concerning requirements R1 and R2 addressing priori prohibitions and post-agreement to comply with an identified Reliability Directive. Cowlitz can see no Reliability difference between

Organization	Yes or No	Question 1 Comment
		an immediate "priori" and post-agreement identification of a TOP Reliability Directive action that would violate safety, equipment, regulatory, or statutory requirements. In each case the outcome is the same: the action is not complied with due to an inability to perform, and the TOP is informed "upon recognition." Therefore R1 and R2 are effectively duplicitous in this regard. Cowlitz suggests that the verbiage "...the respective entity informs its Transmission Operator that..." be removed from requirement R1. Cowlitz agrees with the SDT concerning "Reliability Directive" is not meant to equate to the urgency of a situation. This standard establishes the authority of the TOP to issue directives, and clear communication of such authority has been requested by this commenter in the past. Cowlitz applauds the SDT's stand on this issue. On all other matters, Cowlitz either agrees or abstains with the SDT.
Commonwealth of Massachusetts Department of Public Utilities	Ballot Comment	Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] "upon recognition" seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be "..immediately upon recognition of the inability to perform a Reliability Directive "within the stipulated or understood timeframe" would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
Electric Market Policy	No	Dominion reads R1 to require an entity to 'carry out' the Reliability Directive. In order to comply with the requirement it must either take actions as prescribed in the Reliability Directive or it must inform the TOP that it can't do so for one of

Organization	Yes or No	Question 1 Comment
		the following: safety, equipment, regulatory or statutory requirements. It is Dominion's expectation that an entity may know whether it has safety, equipment, regulatory, or statutory conflicts with the Directive at the time the Reliability Directive is issued, but this may not always be the case (This is especially true where the Reliability Directive is issued to personnel in a control center as opposed to being directly communicated to the operator of the Element or Facility.) Regardless, whenever an entity determines it can't comply with the Reliability Directive, it must make notification or be non-compliant with R1. When the Reliability Directive has a time component and the entity doesn't comply with the time required, it is non-compliant if it hasn't completed the action(s) required unless it notified the TOP before the time component of the Reliability Directive expires (citing one of the following; safety, equipment, regulatory, or statutory requirements.) This time element guidance is not provided with this standard.
Response: R1 and R2: The SDT expects that Reliability Directives will have a time requirement. If a recipient of a Reliability Directive cannot comply due to the reasons stated in Requirement R1, then it is compliant with Requirement R1. If it does not, however, notify the issuer of its inability to comply, it is non-compliant with Requirement R2. No change made.		
Oncor Electric Delivery	No	For R6- Oncor does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term "negatively impacted interconnected registered entities" is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Southern Company Generation	Ballot	For TOP-001-2: 1) R2 and M2 are confusing due to a mismatch in using

Organization	Yes or No	Question 1 Comment
	Comment	"issued" and "identified". R2 lists the directive as "identified", while M2 lists it as "issued, identified,". It is suggested that the following phrasing be used: "an issued Reliability Directive" or "an identified Reliability Directive" 2) The use of a comma after "control equipment" in the list in R6 would make it easier to understand this requirement. (suggestion: make it match M6). 3) Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP why it is unable to do so. Then, the measure could be than an entity either complied or informed the TOP of its inability to comply.
Response: The language of Measure M2 was adjusted to eliminate this confusion. **M2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2. The SDT agrees and changed Requirement R6: **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
Detroit Edison Company	Ballot Comment	I do not agree with the inclusion of the language "and negatively impacted interconnected NERC registered entities" in R6.
Response: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the		

Organization	Yes or No	Question 1 Comment
affected entities.		
Grand River Dam Authority	Ballot Comment	In R8 we would ask that the words internal and area be left out completely and read as “Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its reliability based on its assessment of its Operational Planning Analysis. “
Response: The SDT considered and did not accept this change in wording. The adjectives are intended to provide guidance concerning the context of this requirement. No change made.		
Northeast Power Coordinating Council Hydro One Networks Inc.	No	In Requirement R2, there is a need to specify how much time should be allowed to “inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.” Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such limits. The maintenance of Interconnection reliability and Bulk Electric System integrity is paramount, and global specifications may or may not be appropriate for a local area. Suggest modifying the appropriate wording to: within a specified time not to exceed the timeframe specified by the TOP. R9 is redundant to R11; delete R9.
Response: R2: The SDT did not accept this change. ‘Immediately’ is not a measurable quantity and would create auditing difficulties.		

Organization	Yes or No	Question 1 Comment
R4: The SDT does not agree the suggested wording improves readability. No change made. R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. It is not duplicative to Requirement R9. No change made.		
Independent Electricity System Operator	No	In Requirement R2, there is a need to specify how much time should be allowed to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator." Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. In Requirement R8, we suggest replacing "internal area" with "BES" for greater clarity. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such exceedances. We suggest the following alternative wording for Requirements R8 to R11. Additionally, we suggest removing R9 since its provisions are already covered in R11. R8. Each Transmission Operator shall inform its Reliability Coordinator of all

Organization	Yes or No	Question 1 Comment
		SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: R2: The SDT did not accept this change. 'Immediately' is not a measurable quantity and would create auditing difficulties.

The suggested language for Requirement R4 was not accepted. The meaning of "…provided that the requesting entity has implemented its comparable emergency procedures,…." is clear and unambiguous.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

R9 was not deleted. This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southern Company	No	It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities. R2 and M2 are confusing due to a mismatch in using “issued” and “identified”. R2 lists the directive as “identified”, while M2 lists it as “issued, identified, “. It is suggested that the following phrasing be used: “an issued Reliability Directive” or “an identified Reliability Directive”. Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP as to why it’s unable to do so. Then, the measure could be that an entity either complied with the requirement or informed the TOP of its inability to comply. I think R2 implies that there may be reasons other than safety, equipment, regulatory, or statutory restrictions that may prevent a Generator Operator from performing an identified Reliability Directive as it refers to the GOP’s “inability” to perform the action and doesn’t specifically reference these restrictions again. I agree with your comment that the best way to handle this would be to combine R1 and R2 into a single Requirement perhaps with the following wording:”R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity is unable to perform the actions required by the Reliability Directive (due to violation of safety, equipment, regulatory, or statutory requirements or other reasons) and informs its Transmission Operator upon recognition of its inability to perform the actions. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]” For R2, The question came up for what was more appropriate - issued or identified, and requested Reliability Directive was also suggested as an option. If the reason for this descriptive term is to clarify that the Transmission Operator has declared “this is a Reliability Directive”, then identified would be the more appropriate descriptive term and should be used in a consistent manner. For R6, we take issue with changing the wording from “telemetering equipment” to telemetry as the former is equipment and the latter implies data. The distinction is that under the current wording, the entity is required to coordinate the outage of the piece of equipment that telemeters data (i.e. the RTU) whereas the proposed change implies that the entity will have to

Organization	Yes or No	Question 1 Comment
		coordinate any outages of telemetered data. This could have significant implications as there may be 1000+ data points being telemetered by an RTU, and each data point may come from a unique piece of equipment in the plant. Is the intent that removal of, say, a pressure transmitter or a MW transducer from service for routine calibration requires notification to the Reliability Coordinator? For R6, Fleet Operations functioning as Generator Operator does not directly notify the RC, but interfaces instead with the PCC. Forwarding rules in GENcomm will deliver notifications to the RC. This impacts the evidence for M6, if the expectation is a direct communication. For R6, The use of a comma after “control equipment” in the list in R6 would make it easier to understand this requirement. (suggestion: make it match to M6). For R9, this is a duplicate requirement and does not add to reliability. This requirement is addressed in TOP-004-2 R1. For R10 and R11, these are duplicate requirements and do not add to reliability. These requirements are addressed in TOP-007-0.

Response: The SDT assumes you meant Requirement R6 in your first comment. This is not an issue if dealing with a marketing entity as it is only dealing with telemetry-related outages between the Transmission Operator or Balancing Authority and that entity itself. No change made.

The wording of Measure M2 has been altered to remove ambiguity from the use of the term “identified”.

> **M2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns.

> **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

> **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R6: Agreed and change made.

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R9, R10 and R11 are not redundant as this project is retiring TOP-004-2 and TOP-007-0. No change made.		
ITC	No	ITC thanks the SDT for their work, and believes this iteration of the standard contains improvements. However, we have the following comments and concerns. Regarding the definition of "Reliability Directive", we believe that a clarifier should be added to indicate that a Reliability Directive is "a communication initiated AND IDENTIFIED......". The addition of the words "and identified" makes very clear that the intitiating entity must identify a communication as a Reliability Directive, and thus triggering all requirements related to the Directive. Regarding R6: ITC is concerned with the requirement that impacted "NERC registered entities" be notified of certain conditions. This puts the operating personnel in the position of having to consult the NERC Registry every time an event or action covered in this requirement occurs. Recognizing that is is not an optimal use of our operating personnel, we believe that "NERC registered" should be struck and therefore the requirement would simply require notification of "...negatively impacted interconnected entities". Regarding R8: ITC is concerned that this requirement essentially raises SOL to the same level as an IROL, which of course they should not be. We also share DECs concerns regaring this requirement that TOP actions for local reliability should not be in a mandatory reliability standard. To quote from the DEC submitted comments: "In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very

Organization	Yes or No	Question 1 Comment
		clearly doesn't meet the guidelines." [End DEC comment quote]. ITC further concurs with the MRO NSRF submitted comments that "SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled seperation, or cascacing outages)."
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R8: This requirement was added due to comments from a significant portion of the industry during the extensive posting process of these standards. The requirement does not elevate SOLs to the same status as IROLs, it elevates certain, selected SOLs at the discretion of the Transmission Operator based on analysis which would seem to coincide with the thoughts expressed in the comment. The change has not been accepted.		
MidAmerican Energy Co.	Ballot Comment	MidAmerican does not agree with the SDT reasoning for applying a general industry concept of 30 minutes to SOLs. The NERC standards did not call out at 30 minute time frame for SOLs and to do so equates SOLs with IROLs. The SDT should change all SOL references to IROLs or drop the 30 minute time frame. If the SDT does not elect to drop this, they should at a minimum define a subset of non-thermal SOLs that are shown by TPL or operational studies to cause instability, uncontrolled separation, or cascading as defined by the 2005 Federal Power Act. MidAmerican does not agree with the inclusion statement of non-BES assets or assets below the defined bright line 100 kV threshold. The reference should be deleted. The NERC standards apply to 100 kV and greater assets and all assets below 100 kV should be defined as distribution by default according to the 2005 FPA act definition, unless shown by TPL and operational studies to cause instability, uncontrolled separation, and cascading.

Organization	Yes or No	Question 1 Comment
		In addition, please see the MRO NSRF comments submitted
Response: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
Wisconsin Electric Power Company	No	R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.
Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator.		

Organization	Yes or No	Question 1 Comment
R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R10: Balancing Authorities have no responsibility for line flows. No change made. Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Imperial Irrigation District	Yes	R5 - should include notification of the Reliability Coordinator involvingAdverse Reliability ImpactM1 (b) - did not comply with the indentified directive and informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1.M5 - include the notification to the Reliability Coordinator known or expected to result in an Adverse Reliability Impact Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5
Response: R5: Suggestion was accepted and the requirement and measure were modified accordingly. **R5**. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such		

Organization	Yes or No	Question 1 Comment
communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. **M5**. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.		
City of Green Cove Springs	Ballot Comment	R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. GCS suggests adding the phrase “or cause an SOL or IROL to be exceeded” to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply? R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as “direct others” and “limit the magnitude and duration”, ought to be included in R7 and R9 instead. The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed to meet the next day’s peak load plus contingency reserve requirements, frequency reserves and regulation service (at least that's how we interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAL-002-0 requires that a BA have enough contingency reserves, but, it is unclear as to whether a BA is permitted to shed load to achieve those reserves, and how regulation service

Organization	Yes or No	Question 1 Comment
		and frequency reserves are handled.

Response: R5: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator systems. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area.

R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don't know about it, you can't control it and wouldn't be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made.

R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made.

R11: This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation. No change made.

Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

Organization	Yes or No	Question 1 Comment
Alberta Electric System Operator	Ballot Comment	The AESO believes requirements (R9 and R11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary

Organization	Yes or No	Question 1 Comment
		rating and timing associated with each of the ratings. The AESO would also like to see the term "emergency assistance", used in R4, defined.
Response: Requirements R9 and R11: Agreed and changed. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R4: "Emergency assistance", similar to the data specification in TOP-003-2, should not be limited to an arbitrary list included in a requirement. If the Transmission Operator has any tool, method, or solution that can be used to provide emergency assistance to a neighboring Transmission Operator, it should. For example. the Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.		
Constellation Energy Commodities Group	Ballot Comment	The definition of Reliability Directive needs to include: The RC, TOP or BA must clearly state that "This is a Reliability Directive". This would also apply to project 2006-06.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
American Electric Power	No	The draft of R6 states that "Each Transmission Operator, Balancing Authority, and Generator Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment and associated communication channels between the affected entities." The assessment and dissemination of GOP info to the "affected entities" should be the responsibility of the local TOP and RC. It seems inappropriate to request that the GOP make these sorts of contacts, as GOPs would lack the necessary BES info to make a determination as to who should be notified.
Response: Agreed and changed.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Independent Electricity System Operator	Ballot Comment	The IESO respectfully submits the following comments along with our negative vote: 1. TOP-001-2 Requirement R2: This requires each listed entity to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator ." We consider "upon recognition" to be unclear since there is no indication whether the expectation is for entities to inform the TOP immediately or within some defined time. We therefore suggest the alternative wording " immediately inform its Transmission Operator of its inability to perform a Reliability Directive." This wording, while still not perfect does convey an expectation regarding the timeliness of the entity's communication with the TOP. 2. TOP-001-2 Requirement R9 and R11: These set time limits within which exceedances of IROLs and SOLs indentified pursuant to Requirement R8 must be mitigated, Tv in the case of IROLs and 30 minutes in the case of SOLs. We believe prescribing 30 minutes is not appropriate for SOLs identified in R8 and suggest rewording R8, R10 and R11 as indicated below. Additionally, we suggest removing R9 since its provisions are already covered in R11. In Requirement R8, we suggest replacing "internal area" with "BES" for greater clarity. R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]</td></tr>
<tr><td colspan="3">

Response: R2: Agreed. Requirements R1 and R2 were modified.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Requirement R9 is not redundant (see above). No change made.

</td></tr>
<tr><td>Northern Indiana Public Service Co.</td><td>Ballot Comment</td><td>The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case.

Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		distribution facilities into play.
Response: R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
ISO/RTO Standards Review Committee	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes:R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] There doesn't seem to be a need for R9 since this is covered in R11.
ISO New England Inc.	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have

Organization	Yes or No	Question 1 Comment
		been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. We propose the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.---There doesn't seem to be a need for this is covered in R11. Formerly R10, new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. Formerly R11, new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator.

Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees that the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

> **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11) , and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southwest Power Pool	Ballot Comment	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Delete in entirety Renumber R10 to R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]
Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s T_v., or of an SOL identified in Requirement R8. Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.		
Texas Reliability Entity	No	The statement “identified reliability directive” in R1 and R2, of standard TOP-001-2, would be better changed to “reliability directive.” The word “identify” requires action and the standard does not specify how the “identifying “ will be done. Furthermore, if the TOP is issuing a directive, it should be assumed that the

Organization	Yes or No	Question 1 Comment
		directive is a Reliability Directive unless the TOP states that it is not. This position saves time when time is of the utmost importance. The proposed wording as presented will open the door for deliberation when corrective action should be well underway.
Response: The language in Requirement R1 was altered to reduce the possibility of confusion over the word "identified". **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The other suggested changes for Requirement R1 were not accepted. The Reliability Directive was crafted to require positive identification. When time is of utmost importance, it is better for reliability to get the communications exactly right the first time.		
Great River Energy	Ballot Comment	This requirement has the potential of treating SOLs as an IROL
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
James A Maenner	Ballot Comment	TOP-001 R1 "identified Reliability Directive" is subjective and vague; needs to be clearer. TOP-001 R11 is troubling; it seems to elevate SOLs to IROL status. TOP-001 The language "or expected" allows too many variants; better language maybe "as indicated through system or operational studies". The language "internal area reliability" may lead to an interpretation issue and should be defined.
Response: R1: The language was changed to clarify the intent. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.		

Organization	Yes or No	Question 1 Comment
R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. The requirement was not identified in the comments. Presumably this comment concerned Requirement R3. The SDT considered the suggested language but did not accept it because it does not add clarity. R8: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	TOP-001 R11: "within 30 minutes" should be specified by the transmisison operator or owner. TOP-003 R1:"at voltage levels lower than the BES;" should be removed or justified on a case by case basis.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
Wisconsin Electric Power Marketing, Wisconsin Electric Power Co.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator,

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		these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.

Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement.

> **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R10: Balancing Authorities have no responsibility for line flows. No change made.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Lakeland Electric	No	TOP-001-2 Coordination of Transmission Operations R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. This is probably underperforming and FERC will probably not like it. Some other limits to the scope of communications, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations of Bulk Electric System Facilities known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load." I disagree with deleting TOP-008-1 R3 that allows TOPs, after exhausting other methods to alleviate the problem, to open a Facility if it is imminent danger of catastrophic failure. The requirement should be revised and included in TOP-001-2 as something like the TOP shall request permission of the RC to disconnect the Facility if there is a threat of imminent catastrophic failure, the RC can direct otherwise "unless the direction per Requirement (IRO-001-2). R2 can not be implemented or such actions would violate safety, equipment, regulatory or statutory requirements" (IRO-001-2, R3). Exceeding an IROL that might result in a system restoration event with equipment capable of being restored is preferable to waiting for a Facility to be disconnected due to catastrophic failure, still exceeding the IROL due to that disconnection, but resulting in a system restoration exercise with catastrophically failed equipment. An example of this is the 1977 blackout of NYC which was exacerbated by catastrophically failed equipment. On R7 and R9, I'm concerned about the "for how many contingencies" question, e.g., are we held to the same criteria for "extreme contingencies"? The BAL standards have exclusions for multiple contingencies in meeting the performance requirements (e.g.,BAL-002-0 D1.4). There is not such consideration for "Extreme" contingencies in R7 and R9. If a bad event occurs beyond the criteria we operate the system to, are we setting ourselves up for failure and fines?

Organization	Yes or No	Question 1 Comment
Response: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator system. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area. Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. No change made. Requirements R7 and R9 simply state you must not operate outside IROLs and the non-IROL SOL subset. They do not define how IROLs and SOLs get created. Creation of IROLs and SOLs is governed by FAC-011-2 and FAC-014-2. FAC-011-2 establishes how contingencies must be considered including if any multiple contingencies (FAC-011-2 R3.3) must be included. No change made.		
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] "upon recognition" seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be "..immediately upon recognition of the inability to perform a Reliability Directive "within the stipulated or understood timeframe" would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT modified Requirements R1 and R2. However, 'immediately' is not a measurable quantity and would create auditing difficulties. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
New Brunswick System Operator	Ballot Comment	TOP-001-2 R9, 10 and 11 that stipulates returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be

Organization	Yes or No	Question 1 Comment
		modified to allow the TOP and RC to determine the appropriate time frame for correcting such limits.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
Lakeland Electric	Ballot Comment	TOP-001-2 The words "that are known or expected to be affected" in R3 and "known or expected to result" in R5 may seem reasonable until you look at the VSL table and question the risk of have a PV because the TOP overlooked a notification of marginal value under these requirements in the heat of battle because the condition was not expected to impact an entity.
Response: The Operational Planning Analysis points to those "expected to be affected." No change made.		
South Texas Electric Cooperative	Ballot Comment	TOPs should not be expected to notify other TOPs of problems. That should be the responsibility of the RC or the BA - whomever the TOP is reporting to should have the responsibility of consolidating reports and notifying affected entities accordingly.
Response: The Transmission Operator must coordinate with its neighbors. This is the lynchpin of coordinated operations. No change made.		
Consumers Energy	Ballot Comment	We concur with most of Duke Energy's comments. We further add that we are especially concerned with the definition of Reliability Directive which is ambiguous at best. In TOP-001-2, R2 there is a statement of "upon recognition" in dealing the informing the TO of an inability to follow a Reliability Directive. This is vague and very difficult to document. It is unfortunate but the transition to legalistic interpretations of standards, a task often defaulting to audit team personnel, makes it absolutely mandatory that the expectations for proof of compliance be improved to be totally clear.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition.		

Organization	Yes or No	Question 1 Comment
Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made. R2: This language was deleted. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
MRO's NERC Standards Review Forum	No	We disagree with the statement in R8 ". . . have been identified by the Transmission Operator as supporting its internal area reliability . . .". This statement puts an SOL on the same level as an IROL, which is not the intent of an SOL. The Transmission Operator should inform the Reliability Coordinator of IROL's that may impact the reliability of the BES, but not SOL's. R9 - We continue to believe that SOL's should not be a part of the TOP-001-2 standard. There are not identified timeframes in the NERC standards that apply to SOL's. There has been no basis for the 30 minute timeframe listed, as "generally accepted by the industry" is not a technical basis, and SOL's are often tied to thermal limits and other steps can be taken locally to offset the SOL. If SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded. An example definition might be "non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability."Including SOL's in R11 effectively makes them equivalent to IROL's for mitigation purposes. Consistent with our comments in R8 and R9, SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled separation, or cascading outages). The SDT should ensure that TOP-001 consistent with FAC-014-2 R2 concerning identification of SOLs.
Response: R8: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous		

Organization	Yes or No	Question 1 Comment
duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
FirstEnergy	No	We have the following comments and suggestions:1. R3 - Since this requirement is describing actions to be taken in Real-time as shown in the Time Horizon, the use of the term "Operational Planning Analysis" may not be appropriate. This is because an analysis in the operations planning timeframe is restricted to next day and up to 12 months in the future. We suggest that the team reconsider of the use of this phrase and remove the last part of this requirement, specifically remove "based on its assessment of its Operational Planning Analysis". 2. R6 - We do not agree with the phrase "and negatively impacted interconnected NERC registered entities". We believe that it should be the responsibility of the Reliability Coordinator to notify all impacted entities since they are afforded the wide-area view of the area. 3. R6 - The phrase "control equipment" is too broad and lacking clarity with regard to the phrase "between the affected entities". We suggest that additional clarification be added by providing examples of the types of control equipment or the loss of functionality that could occur due to the outage.
Response: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The SDT does not agree that Transmission Operators should not coordinate with neighboring Transmission Operators. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. However, other changes were made in Requirement R6 to help with clarity.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
East Kentucky Power Coop. Southwest Transmission Cooperative, Inc.	Ballot Comment	We thank the standards drafting team for their efforts in drafting this set of standards and believe they are significantly improved over the existing standards. We have identified some issues that warrant additional consideration by the drafting team. While TOP-001-2 R8 is an improvement of the existing TOP-004-2 R1, it introduces new ambiguity into the standards. What criteria should the TOP use for identifying the subset of non-IROL SOLs? If the TOP has a procedure/process document that defines how it identifies these SOLs and follows that procedure/process, will it be compliant with the requirement? Can the TOP ever be second-guessed on its list? The clause “that represents projected System conditions” is redundant with the definition of Operational Planning Analysis in TOP-002-3 R1. To avoid confusion, TOP-002-3 R2 should reference that the SOLs are those identified in TOP-001-2 R8 similar to how TOP-001-2 R11 references it.
Response: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase ‘internal area reliability’ was left undefined to encompass each of these unique challenges. The SDT believes the Transmission Operator cannot be second-guessed on this list. No change made. The SDT considered deletion of this phrase; however, it provides clarity for this requirement and does not introduce ambiguities. No change made. The SDT agrees and has made conforming changes to TOP-002-3, Requirement R2.		
LG&E and KU Energy PPL Supply	No	While LG&E and KU Energy generally agrees with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of

Organization	Yes or No	Question 1 Comment
		safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. LG&E and KU Energy does not believe that these two requirements need to be separated.Moreover, to the extent there are duplicative requirements for the same issue, if a violation were to occur, an entity may be in violation of two requirements instead of one. The standards must clearly state what is required and must do so without creating duplicative or overlapping requirements or sub-requirements. As presently drafted, R1 and R2 create confusion as to what is required and could result in multiple self reports for the same potential violation and potentially additional penalties as a result of two violations for what appears to be the same issue. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. LG&E and KU Energy thinks “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 - No comments R5 - LG&E and KU Energy recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. The requirement is unclear in describing who is responsible for informing whom, needs to be rewritten to clarify. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? Additionally, please clarify what is intended by terms “negatively impacted interconnected NERC entities” and “control equipment” as used in proposed R6. R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. Based on the NERC definition Operational Planning Analysis is considered future looking (next-day through 12 months) this would exclude modification to SOLs made during Real-time Operations.SOLs utilized in Operational Planning Analysis are based on certain assumptions given forecasted conditions or historical data. Real-time operating conditions can vary drastically from these assumptions and there

Organization	Yes or No	Question 1 Comment
		needs to be flexibility in modifying SOLs to account for these actual system conditions. R9 - The 30 minute duration is quite restrictive in resolving an SOL exceedance, especially for those that are considered to support internal area reliability. Does this apply only to actual SOL exceedances, or does it also include post-contingent SOL exceedances? LG&E and KU Energy feel the time limit should be at least 90 minutes for exceeding an SOL (especially for post-contingent SOLs), to allow for use of TLR procedures or other measures which often take more than 30 minutes to implement.There needs to be some flexibility in establishing Real-time Operations SOLs based on actual system conditions separate from the Operational Planning Analysis. R10 - Because the Time Horizon is "Real-time Operations" the SOLs communicated to the RC per this requirement should be the Real-time Operations established SOLs, not the Operational Planning Analysis SOLs established in R8. R11 - The SOLs established in R8 deal with future looking Operational Planning Analysis, however this requirement deals with Real-time Operations. Need clarification about Real-time Operations SOLs and we suggest the time duration for SOLs exceedances should be at least 90 minutes as described in R9.

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or

Organization	Yes or No	Question 1 Comment
expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R10 – For SOLs discovered in real-time, the Transmission Operator doesn't need to inform as it is an SOL and hasn't been previously reported to the Reliability Coordinator. No change made. R9 and R11: Agreed and language changed to reflect the intent of the suggested changes. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
SERC OC Standards Review Group	No	While we generally agree with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. The group does not feel that these two requirements need to be separated. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. (We think "assessment" is synonymous with "analysis"). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning.

Organization	Yes or No	Question 1 Comment
		R4 - No comments R5 - We recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. R9 - We feel the time limit should be 90 minutes for exceeding an SOL, to allow for use of TLR procedures or other measures. R10 and R11 - Logically these two requirements should be swapped so that the requirement to act is performed prior to notification of actions taken. The reference to 30 minutes should be changed to 90 minutes (see comment to R9 above).

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R9 and R11: Agreed – the 30 minute time limit was deleted. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R10 – The requirements are not sequential. No change made.		
Progress Energy	No	
Response: Without specific comments, the SDT is unable to respond.		
Florida Municipal Power Agency	No	R5 requires communications / coordination more than the version 1 standard (old R7) to those actions that can result in an Adverse Reliability Impact, which are very few and is ambiguous. FMPA suggests adding the phrase "or cause an SOL or IROL to be exceeded" to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." Also, there seems to be overlap of responsibility with the RC in real-time operations concerning SOLs and IROLs. FMPA can certainly see informing the RC and neighboring TOPs of a potential SOL / IROL in an Operational Planning Assessment, but, in real-time, that may be too much of a burden and might step on the RC's toes in efficient and effective communication and coordination. R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply?

Organization	Yes or No	Question 1 Comment
		R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as “direct others” and “limit the magnitude and duration”, ought to be included in R7 and R9 instead.
Response: R5 – The language of Requirement R5 was changed due to comments from others and it now provides better clarity as to the SDT’s intent. **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. The SDT does not see an overlap. The Transmission Operator is responsible for all SOLs and for informing the Reliability Coordinator of the subset of SOLs that will receive greater scrutiny. No change made. R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don’t know about it, you can’t control it and wouldn’t be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Manitoba Hydro	Yes	The term ‘reliability entity’ used in TOP-001-02 should be changed to ‘registered entity’.
Response: The SDT reviewed TOP-001-2 and could not locate any instances of “reliability entity” to change. “Registered entities” was used in Requirement R6.		
Northeast Utilities	Yes	Suggest rearranging R4 to read: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures.
Response: The SDT considered this suggestion but did not accept it. This change does not add clarity. No change made.		
Pepco Holdings Inc	Yes	Should the standard be applicable to a TO? Specially it would appear that R1 and R2 should be applicable to a TO in addition to the other listed entities.

Organization	Yes or No	Question 1 Comment
Response: All transmission facilities must have a Transmission Operator. This applies to operators not owners.		
BGE	Yes	Comment on proposed TOP-001-2 Reliability Directive definition: Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.This needs to also include: The RC, TOP or BA must clearly state that “This is a Reliability Directive”.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
City of Tacoma or Tacoma Public Utilities	Yes	1. The Standard Development Roadmap, page 2, states there are no new or revised definitions yet there is a revised definition for “Reliability Directive.” Reliability Directive is not listed in NERC’s Glossary of Terms. 2. The terms “Operational Planning”, “Same Day Operations” and Real-time Operations” need definitions that include a time horizon. 3. R1: The language is redundant with R2. Removing “...the respective entity informs its Transmission Operator that...” from R1 would eliminate the redundancy. 4. R5: New R5 language replaces the old language from TOP-001-2 R 7.3.Proposed: “Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, transmission or load.”Existing R7, R.3:”When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generation Operator shall notify the Transmission Operator and the Transmission Operator shall notify its Reliability Coordinator and adjacent Balancing Authority, at the earliest possible time.”Suggestion - Include language to identify the time requirement for communications including after-the-fact notifications. The purpose of the requirement is to inform, yet there is no associated timeframe. 1. R10: Similar to R5, this requirement also needs an associated timeframe to

Organization	Yes or No	Question 1 Comment
		inform the RC, otherwise it's difficult to measure.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. It is shown here for the reviewer's convenience. No change made. Time Horizons are defined at NERC: http://www.nerc.com/files/Time_Horizons.pdf R1: Agreed and conforming changes were made. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. R5 & R10: There is no definable timeframe for all conditions consistently and objectively measurable. No change made.		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Luminant Energy	Yes	
Western Electricity Coordinating Council	Yes	
Luminant Power	Yes	
Indeck Energy Services	Yes	
ReliabilityFirst	Yes	
Puget Sound Energy	Yes	
Georgia Transmission Corporation	Yes	
Response: Thank you for your support.		

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The SDT made a few minor clarifying changes in response to comments received. The SDT does not consider the changes to be substantive.

The SDT revised Requirement R2 of TOP-002-3 to read as a positive statement rather than as a double negative. The change is simply a restatement without changing the meaning of the requirement, but should be clearer now.

A few commenters were concerned with the use of what they believed to be a definition that is not included in the Glossary of Terms used in NERC Reliability Standards. The definition of concern is that of Operational Planning Analysis. The definition is in the glossary, so the SDT doesn't understand the comments and no change was made.

The SDT made a clarifying change to Requirement R3 of TOP-002-3 by adding the term "NERC" as a modifier of "registered entities".

The SDT made revisions in TOP-001-2 to clarify the time relating to the exceedance of the subset of SOLs that, while not IROLs, has been identified by the Transmission Operator as supporting its internal area reliability. Concerns were expressed that 30 minutes was not applicable to all SOLs. The SDT agrees and has made the clarifying changes.

Some commenters were concerned with the notifications indicated in Requirement R3 for entities identified in an operating plan. Some of the commenters said it could be read to mean all entities have to be notified. The SDT reviewed the comments and the wording and did not agree that the language needed to be changed. The standard describes "what" must be done; namely, review and plan how to address predicted exceedances, but does not specify "how" to do the plan, which would be unnecessarily prescriptive. When the Transmission Operator performs its planning activities, those entities identified as having a role in the mitigating actions are identified. It is only those entities that will have a role in the execution of the plan that must be notified.

R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their

role in those plan(s).

Organization	Yes or No	Question 2 Comment
City of Tacoma or Tacoma Public Utilities	No	R2: "Each Transmission Operator shall plan to preclude operating in excess of Interconnected reliability Limits (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified as supporting its internal area reliability, as a result of the Operational Planning Analysis performed in Requirement R1."Suggestion - The statement in red is a double negative and difficult to follow. Rewrite this sentence to be a positive statement to avoid confusion, for example, "Each Transmission operator shall plan to operate within identified ..."
Response: The SDT agrees and has revised Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Duke Energy Duke Energy Carolina	No	This standard uses the capitalized term "Operational Planning Analysis" which is not currently a NERC defined term. How is this to be applied in the standard? o R2 - We reiterate our comments on TOP-001-2 regarding the problematic phrase "supporting its internal area reliability". Will an entity's Operational Planning Analysis be found deficient if no SOLs have been identified which support "internal area reliability"? We believe that it is certainly possible. Furthermore, in M2, what evidence will be required to be presented to demonstrate that an entity has no SOLs which "support internal area reliability"? o R3 - insert the word "NERC" before the word "registered" to add clarity.
Response: The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reminds you the Transmission Operator has primary responsibility for all System Operating Limits (SOLs) within its purview (or footprint or area). The requirement is for the Transmission Operator to decide which of its SOLs rise to a greater degree of importance to its internal area reliability such that the Transmission Operator wishes the Reliability Coordinator to join in monitoring and controlling system parameters within the SOL(s). If the Transmission Operator does not believe it has any such SOLs, it is not required to notify the Reliability Coordinator of any. No change made.		

Organization	Yes or No	Question 2 Comment
The SDT has added the word “NERC” to provide clarification. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Ameren	No	(1)R1 refers to “Operational Planning Analysis” which is not a defined term. Similarly, R3 uses the phrase “registered entities identified in the plan(s) cited in R2 which is confusing. Please define/clarify these terms or phrases. (2) In R2 (similar to R8 in TOP-001-2) , what is meant by “internal” area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited.
Response: The term “Operational Planning Analysis” is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reviewed the questioned language and, after discussion, does not understand what is causing the confusion. No change made. The SDT changed “local area” to “internal area” based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT believes that area is its “internal area” and does not involve crossing boundaries or affecting other Transmission Operator area(s). No change made.		
MRO's NERC Standards Review Forum	No	believes that the boundaries are not identified in TOP-002-3 R2. For IROLs, the boundaries should be limited to the Registered Entities footprint.
Response: The SDT disagrees. IROLs definitely may involve crossing boundaries between registered entities’ footprints. Operations within one area may affect system flows or other parameters within other areas, or the limits may be on interconnecting facilities. Typically the Transmission Operator has the most granular and specific information for the system facilities within its area, but the Reliability Coordinator has a widespread view, albeit that it may be at a higher level and less granular. The plans of the Transmission Operator that are relevant to Requirement R2 are those plans the Transmission Operator will implement to ensure operating actions within the IROLs and SOLs. The Transmission Operator is also required to notify other entities which will have a role in the execution of those plans. Therefore, there are many different potential combinations of areas and boundaries and possible interconnecting facilities between areas that may be involved in such operating action plans. No change made.		
Electric Market Policy	No	Dominion is unsure as to which version (clean or redline) of the language in the grey box (for R1) the SDT intended. The sentence (in red line version) appears to read “Rationale for Requirement R1: Operational Planning Analysis (OPA) does not the analysis even if those

Organization	Yes or No	Question 2 Comment
		tools are not available." Please clarify. We also did not find any changes to the Data Retention (red line version).
Response: The clean version is the correct version.		
City of Green Cove Springs Florida Municipal Power Agency	Ballot Comment	GCS still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day / next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). GCS is proposing that this temporary requirement would be retired with the new BAL standard. GCS suggests that TOP-002-3 include a temporary requirement for BA's to validate unit commitment that meets the current day / next day projected peak loads plus reserve requirements until it is included in the BAL standards and at which time the requirement in the TOP standards could be retired. Operational Planning Analysis is ambiguous. R1 doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1. It also does not talk about what is being studied, e.g., the same contingencies included in the RC SOL methodology of FAC-011 for instance. GCS suggests defining the capitalized term of Operational Planning Analysis and add it to the NERC Glossary, especially since it is a capitalized term in the standard. R2 is confusing. We are sure the intent is that, if the Operational Planning Analysis results show that an SOL or IROL would be exceeded as a result of single / double contingencies covered by the RC's SOL Methodology of FAC-011, then the TOP must develop a plan to resolve the situation within the Tv of the SOL or IROL. GCS recommends that the SDT redraft R2 to make it less confusing and add clarity, maybe something like: "Each TOP shall develop plans to relieve an SOL or IROL violation identified in the results of Operational Planning Analyses within the time constraints related to the SOL or IROL (e.g., within the time frame of emergency ratings or the IROL Tv)" Such a change will also help clarify which entities are notified in R3. Currently, R3 is ambiguous as well since R2 as currently drafted seems to indicate that the Operational

Organization	Yes or No	Question 2 Comment
		Planning Analysis itself if the plan, and since everyone has a role in that plan, then R3 seems to indicate that everyone needs to be notified, which we doubt is the intent of the SDT.

Response: Regarding the removal of the Balancing Authority:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

The timeframe of the Operational Planning Analysis is part of the definition. No change made.

The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made.

TOP-001-2 has been revised to more clearly address the time relating to the exceedance of the subset of SOLs that is included in the limits that the Transmission Operator has informed the Reliability Coordinator to be important to the Transmission Operator's internal area.

The SDT did not intend that everyone would have a role in the plan. The Transmission Operator would identify the entities that would have responsibility for the facilities that would be involved in the execution of the operating plan. Those are the only entities that must be notified, not all entities. No change made.

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	NPPD does agree in general with the intent of the proposals under this ballot, however there is change needed in TOP-002-3. The language in TOP-002-3 R2 is not clear and could be interpreted to require an entity to include all IROL's in the interconnection, which is way too broad. NPPD suggests that R2 of TOP-002-3 be reworded to be clear that the requirement is addressing IROL's and SOL's "within the Transmission Operator's Area".

Response: The Reliability Coordinator and the Transmission Operator must work in coordination and close communication. The Reliability Coordinator is expected to discuss with the Transmission Operator those areas and facilities within its area that are involved with, or can impact, IROLs and, possibly some of the SOLs that the Transmission Operator or other Transmission Operators have identified as affecting their internal area reliability. To be sure, there are IROLs and SOLs in the Bulk Electric System (BES) that any given registered entity may not be able to affect,

Organization	Yes or No	Question 2 Comment
either positively or negatively. However, each IROL is the responsibility of a Transmission Operator. The Transmission Operator is obligated to notify those entities that have a role in its plan to resolve the IROL. No change made.		
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	No	R1 - No comments R2 - The word “preclude” can be interpreted as “prevent”, which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as “avoid” should be considered. R3 - No comments
Response: The SDT has revised the wording of Requirement R2 in response to comments. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Southern Company	No	R1 -It is still unclear to us if Operations Planning Analysis includes Contingency analysis as the NERC Glossary does not explicitly state. Edits to the rationale box were such that we could not understand the intent. R3-Is the standard expecting a comprehensive written plan as a result of the planning that takes place in R2? Is the intent of this requirement to notify all registered entities that may be affected by a mitigation plan for the next day?Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the transmission operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5. It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities.
Response: The SDT has corrected an editing problem related to Requirement R1 and the text box. Requirement R2 doesn’t mandate a written plan, but Measure M2 points to plans and processes. Typically plans in written form are easier to use to present evidence that a plan exists. Measure M2, therefore, recognizes written plan(s) as one option. Requirement R2 requires the Transmission Operator to plan. Without being so prescriptive as to tell “how” to do this, the SDT believes that the		

Organization	Yes or No	Question 2 Comment
Transmission Operator, in conducting its planning, will identify potential problem areas and what actions may be required to address those areas. The Transmission Operator must identify other entities which will have a role in executing any operating action plans that will be required to resolve issues as they arise. The SDT recognizes there are many different organizational structures and contractual arrangements in various areas of the BES. Each registered entity knows the arrangements that are in place for its facilities; for instance, generators are typically re-dispatched through Balancing Authorities and Generator Operators. It is not possible to specifically state each procedural action that must occur for this to take place. If the Transmission Operator typically calls the Balancing Authority, then the Balancing Authority knows how to implement the required actions. No change made. The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Wisconsin Electric Power Company	No	R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered.
ITC	No	Regarding R3: Consistent with our comments on TOP-001 R6, we believe that the use of the word "registered" entities does not provide value, and only adds an unnecessary administrative step to operating personnel. We recommend just using "entities".
Response: The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
City of Vero Beach	Ballot Comment	The City of Vero Beach still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day/next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). The City of Vero Beach is proposing that this temporary requirement would be retired with the new BAL standard.

Organization	Yes or No	Question 2 Comment
Lakeland Electric	Ballot Comment	The new standard is just the TOP, which is appropriate; the old TOP-002-1 basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed(interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAs are eliminated from the new version 2 standard, and with no similar requirement in the BAL standards, FERC will likely see a reliability gap, no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment.
Lakeland Electric	No	TOP-002-3: Operations Planning The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed (at least that's how I interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). Since BAs are eliminated from the new version 2 standard, and since there is no similar requirement in the BAL standards that I am aware of, FERC will likely see a reliability gap that no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment. The SDT claims that BAL-001-1 covers the operations planning perspective of a BA, but, BAL-001-1 covers unit commitment only loosely on an annual or monthly basis. The new version also doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1.

Response: Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

Organization	Yes or No	Question 2 Comment
Progress Energy	No	TOP-002-3 R2...Our initial concern was that an auditor could read this requirement as requiring a specific plan to address each IROL and SOL. This interpretation does not make much sense, but it is supported by the wording of the measure, which says, “Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL.” We can picture an auditor going down a complete list of IROLs and SOLs and asking, where is your plan for A, where is your plan for B, etc.The standard should not require the Transmission Operator to prepare a plan to address IROLs and SOLs unless the Operational Planning Analysis indicates the potential for a thermal or voltage problem for that element due to normal (N-0), contingency (N-1), or sensitivity analysis result. So, the logical way to read this requirement is to say that the completion of the Operational Planning Analysis is the “plan”, and if there are no IROL/SOL limits exceeded, then you have met the requirement. If this is what the SDT meant, then the wording of the requirement should be revised and clarified. Also, We are concerned about the requirement to “...plan to preclude operating in excess...”, because “preclude” is defined to mean “make impossible” or “take action in advance to make impossible”. Precluding these events is inconsistent with the time limits established in the new TOP-001-3 standard. This could be read to require pre-contingency action for any contingency involving an IROL/SOL, which could cause major operational problems to say the least. All of the prior standards, including the TOP, TPL, and the Rules of Procedure governing the seasonal assessment process provide latitude in how studies are performed, and what pre- and post- contingency actions are taken. This standard should be clarified to provide comparable latitude in addressing IROL and SOL issues. Just changing “preclude” to “mitigate” would be a good start.... Also, requirement R2 is unacceptably vague in that it requires plans for SOLs that “support internal area reliability” without indicating how those SOLs are identified or selected as a subset of all SOLs. Also, R8 of TOP-001-3 requires that the RC be notified of the existence of these SOLs, whatever they are....

Response: The SDT believes that Operational Planning Analysis (OPA) will identify areas that need specific attention and specific plans. A Transmission Operator may have a standing practice of constraint management which will address the great majority of IROL or SOL requirements. In such a case, evidence of the existence of such a practice and evidence that the practice was followed will address the requirement. For those issues identified in the OPA as needing specific operating action plans, the Transmission Operator can show how each is covered in its procedures or, when required, in case-specific plans. Such plans may be standing or temporary, depending upon the system conditions involved. The standards are not prescriptive as to “how” the entity is to address the issues, just what the entity is required to do. No change made.

The SDT has revised the wording of Requirement R2.

Organization	Yes or No	Question 2 Comment
R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed “local area” to “internal area” based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities respects the difficulty in crafting language which satisfies all potential interpretations of a requirement. We do, however, suggest changing "planning to preclude operating" under R2 to "plan to operate", giving you the following: “Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator via the Operational Planning Analysis performed in Requirement R1 as supporting its internal area reliability.”Perhaps the definition of SOL should be revised to include the principle of "internal area reliability". Then, everything not IROL or SOL could go back to being facility ratings or the like.
Response: The SDT has revised the wording of Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed “local area” to “internal area” based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Yes		
Yes		
Yes		

Organization	Yes or No	Question 2 Comment
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Organization	Yes or No	Question 2 Comment
Yes		
Yes		
Yes		
Response: Thank you for your support.		

3. **The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments were asking for clarification. The SDT made specific changes to Requirements R2 & R3 to spell out that the intent of the SDT is to allow the Transmission Operator and Balancing Authority to request any data they need to perform their monitoring and operations planning functions as long as the entity has a reliability-based need for that data. The SDT also deleted the two sub-bullets in Requirement R1 in this same vein.

R2. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements.

R3. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .

Organization	Yes or No	Question 3 Comment
City of Tacoma or Tacoma Public Utilities	No	1. In general, the standard language as written is vague. 2. R1: Though a minimum list of required data may be construed as too prescriptive and may "stifle creativity and innovations," the absence of a pre-defined list will promote inconsistencies between entities and may risk an Auditor interpreting what data is needed for an "Operational Planning Analysis" differently from the utility. 3. R1.1: The term "long term outages" needs a definition. How long is "long term?" 4. R1.1: The term "operating parameters" also need a definition.

Response:

1. Without a specific comment, the SDT is unable to respond. No change made.
2. The noted audit concern can never be eliminated based on the reality that auditors may incorrectly cite an audited entity for actions or items not required by the standard. Requirement R1 is actually quite specific – the data specification limits the data to be provided as only that data explicitly requested by a Transmission Operator or a Balancing Authority. If the data is not on the list, than the data need not be supplied regardless of what an auditor considers as necessary. A given auditor may find the entity non-compliant but that non-compliance should be

Organization	Yes or No	Question 3 Comment
overruled based on the requirement as written. No change made. **3.** (and 4.) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
MRO's NERC Standards Review Forum	No	As currently written, R1.1 could be interpreted to include all of the distribution facilities of a Registered Entity. It needs to be revised to include only the lower voltage facilities proven to impact the reliability of the BES. In R1.1, please clarify "long-term" as the term applies to outage of BES Facilities. What length of time must pass before an outage I is considered "long-term"? In R1.1, clarify "Operating Parameters" as the term applies to BES Facilities and those Facilities at voltages lower than the BES. We recommend that a list of required parameters be included within the Requirement. Recommend rewording R2 (and R3) as follows: "Each Transmission Operator shall distribute its data specification document to all NERC Registered Entities that provide Facility status to the Transmission Operator."
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. The technical issue raised by the commenter will not be resolved by the proposed rewording. The proposed rewording is to have the requesting entity send documentation to those that already provide data. The proposed rewording begs the question of what to do with new entities, or entities that have changed Transmission Operators. However, the SDT has made clarifying changes to the wording of both requirements. **R2**. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis.		
Cowlitz County PUD	No	Cowlitz has no disagreement with any of the changes made; however Cowlitz struggles why the Load-Serving Entities (LSEs) are included in the Applicability section. From requirements R2 and R3 it is clear that Facility monitoring and status is involved. From the Reliability

Organization	Yes or No	Question 3 Comment
		Functional Model it is clear that LSEs do not own Facilities, but rather are more ambassadors between the End-use Customers and registered entities that do own facilities. Although the Statement of Compliance Registry Criteria implies that the LSEs might own UVLS and/or UFLS equipment, the Reliability Functional Model is clear that the LSE only helps identify those critical customer loads that should be excluded in such load shedding programs. Therefore, Cowlitz urges the SDT to remove the LSEs from the Applicability section. Cowlitz also suggests that Distribution Providers be included in the Applicability section as these entities do own Facilities that may require monitoring and status by the TOP and BA.
Response: Load-Serving Entity's have load data that is necessary to conduct an Operational Analysis. While a Load-Serving Entity may be by default required to provide such information, that does not mean that every Load-Serving Entity will be asked to provide such information (as some reliability entities provide their own composite forecast loads and do not need each Load-Serving Entity's forecast.) No change made. There are no other comments that there is any data needed by the Transmission Operator or Balancing Authority that must be supplied by the Distribution Provider. No change made.		
Illinois Municipal Electric Agency	Ballot Comment	Illinois Municipal Electric Agency (IMEA) appreciates the SDT's efforts on this initiative to simplify and improve this set of Reliability Standards. We are supportive of those Requirements which apply to the DP, LSE, and TO functions; however, IMEA is voting Negative to support concerns which have been expressed to remove the following language from TOP-003-2, R1.1: "and Facilities at voltage levels lower than the BES."
FirstEnergy	No	R1 - Subpart 1.1, Bullet #2 - We suggest that the team strike the phrase "and Facilities at voltage levels lower than the BES". NERC reliability standards are meant to provide an adequate level of reliability to the Bulk Electric System, and therefore non-BES requirements are beyond the scope of the standards. Furthermore, the current NERC initiative to revise the definition of BES and provide specifics around what is both included and excluded will alleviate any potential gaps in reliability of the BES.
Georgia Transmission Corporation	No	Section 215 of the FPA provides that the ERO "shall have authority to develop and enforce compliance with reliability standards for only the BPS."In Order 743A, the commission acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy" from the BPS definition.R1.1 for TOP-003-2 references distribution assets which are outside the scope of NERC standards. GTC recommends removing reference to "Facilities at voltage levels lower than the BES"
Commonwealth of Massachusetts Department of	Ballot Comment	The other issue is in TOP-003-2 R1.1 which states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to

Organization	Yes or No	Question 3 Comment
Public Utilities		perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. Some RSC members believe using language such as "but not limited to" and "levels lower than the BES" to be problematic and beyond the scope of what is needed and also creates potential for compliance issues.
ISO/RTO Standards Review Committee	No	The second bullet under R1, 1.1 facilities "at voltage levels lower than the BES;" we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
ISO New England Inc.	No	The second bullet under R1, 1.1 facilities "at voltage levels lower than the BES;" we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as "but not limited to" and "levels lower than the BES" to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
Pepco Holdings Inc	No	In R1.1 has an open ended requirement for operating parameters for non BES facilities. Should the language limit that to only those facilities that have an impact on BES facilities? If so, should long term outages of those facilities also be required?
PSEG Energy Resources & Trade LLC PSEG Fossil LLC Public Service Electric and Gas Co.	Ballot Comment	In TOP-003-2 Operational Reliability Data, the PSEG companies do not understand the need for the sub-BES voltage data reporting requirement in the second bullet of R1.1. This open-ended requirement appears to be potentially extremely burdensome to LSEs and TOs with no justified basis of its need to maintain BES reliability. If the sub-BES voltage phrase is removed from the Requirement so that it to simply states "Operating parameters for BES Facilities" The PSEG companies expect that they would change their vote to affirmative. Additionally, in TOP-003-2 R1.1, the phase "Long term outages" is interpreted to be planned

Organization	Yes or No	Question 3 Comment
		season outages not emergent issues that result in a long duration outage of a BES facility. Please clarify if this is a correct interpretation of the intent of the SDT.
Duke Energy Carolina	Ballot Comment	3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase “at the discretion of the Transmission Operator or Balancing Authority” must be restored in this requirement. 3. TOP-003-2 Requirement 1, Part 1.1: This provides for exchange of data required to perform Operational Planning Analyses and real-time monitoring. These data include “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES [emphasis added].” We believe the latter clause is unenforceable under the NERC standards and should therefore be removed.
Northeast Power Coordinating Council Hydro One Networks Inc. Independent Electricity System Operator	No	Referring to the second bullet under R1, Part 1.1, “...Facilities at voltage levels lower than the BES;” these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	Yes	R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 - No comments R3 - No comments R4 - No comments
BC Hydro	No	R1.1 refers to “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES”. In the previous Consideration of Comments, it was noted that “Facilities below 100kV may have material impact to the BES and, as such, are within the scope of the requirement ...”. BC Hydro feels that the wording in R1.1 “Facilities at voltage levels lower than the BES” is open-ended and it does not clearly reflect that these extra Facilities have been deemed as having material impact to the BES and therefore are subject to the NERC

Organization	Yes or No	Question 3 Comment
		MRS.
Roger C Zaklukiewicz	Ballot Comment	Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Public Service Enterprise Group LLC	No	The PSEG Companies interprets “long term outages” to be planned season outages not emergent issues that result in a long duration outage of a BES facility.
United Illuminating Co.	Ballot Comment	UI Votes negative due to TOP-003 R1.1 requirement that the TOP can request operating parameters for Facilities at voltage levels lower than the BES. If a facility lower than 100 kV is required to be included in the BES then the exception process should be followed to include it in the BES. Non-BES designated facilities cannot be subject to mandatory reliability standards.
Puget Sound Energy	Yes	The second bullet in R1.1 needs clarification. As originally drafted, this was permissive language allowing entities to include non-BES information in their data specifications. However, with the revisions, this section now requires all entities to do so, whether or not such data is necessary or pertinent for their operations. As a result, the second bullet should be revised to retain its permissive character or should be removed from the standard altogether.
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Ameren	No	In R1, 1.1 “at the discretion of the Transmission Operator or Balancing Authority” phrase should be reinstated.
Response: The SDT has made changes to requirements R2 & R3 to address this issue. As newly worded, this limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator’s		

Organization	Yes or No	Question 3 Comment
reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Electric Market Policy	No	Is this question meant to refer to TOP-003-2? If so, then Dominion's response is that we agree, but do not see why the SDT felt it necessary to add "web postings with acknowledgement" to M2 and M3. The sentence "Such evidence could include but is not limited to ...." was sufficient without the addition. Dominion believes this language will invite others to want to add the types of evidence found usefher may grow over time.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
ITC	No	ITC is concerned with the removal from R1.1 of the phrase "...at the discretion of the Transmission Operator or Balancing Authority". Why was this removed? The TO and BA should have discretion of what data it needs (especially at the sub-BES level) to perform Operational Planning Analysis and Real time monitoring. Also in R1.1, please define what "long-term outages" are.
Duke Energy	No	The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase "at the discretion of the Transmission Operator or Balancing Authority" must be restored in this requirement.
Response: The SDT made clarifying changes to Requirements R2 & R3 to address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2**. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability		

Organization	Yes or No	Question 3 Comment
monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
PJM Interconnection, L.L.C.	Ballot Comment	PJM questions the 30 minute limitation placed on SOLs that are identified by TOPs for use by the RCs (TOP-001 R9). In addition PJM does not agree with the inclusion of non-BES assets (TOP-003 R1).
Response: (see Q1 for response to 30 min question) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Florida Municipal Power Agency	No	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. FMPA suggests clarifying who is mutually agreeing. Also, from a reliability perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14.R1.3 and R1.4 - should have the same characterization of R1.2,

Organization	Yes or No	Question 3 Comment
		e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitably be too much or too little for another entity. Over the postings of this standard the Industry comments favored the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. There is no implied right given to a Transmission Operator or Balancing Authority to purchase tools that cannot be supported by the assets it coordinates. If there is a new technology that none of its members can support, must the members all be required to install new equipment for that change? The current sub-requirement has not been questioned by any other entity. No change made.		
City of Green Cove Springs	Ballot Comment	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. GCS suggests clarifying who is mutually agreeing. Also, from a reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a

Organization	Yes or No	Question 3 Comment
		schedule. GCS believes significant changes to the standards are required; hence, it is too early to opine on the VSLs.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. Requirement R1 must be viewed in the context that there "may be" more than one data specification used by a Transmission Operator or Balancing Authority. Requirement R1 allows the flexibility to customize specifications for each entity that is being asked to provide data for the operating analysis tools in question. No change made.		
Wisconsin Electric Power Company	No	R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.
Response: The commenters provide no alternative to the term "monitored". Given the limited number of comments regarding this term, no change is made to the requirement. The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.		
Imperial Irrigation District	Yes	Suggestions/Comments: Could R2 & R3 be included as sub bullets of R1 (R1.1 & R1.2)? R1 - Each Transmission Operator and Balancing Authority shall have create and maintain a formal documented plan/procedure for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. R2 - Each Transmission Operator shall distribute its formal data plan/procedure specification to the Reliability Coordinator and entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator.

Organization	Yes or No	Question 3 Comment
		R3 - Each Balancing Authority shall distribute its formal data plan/procedure specification to the Reliability Coordinator and to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.
Response: The SDT believes that including Requirements R2 & R3 as sub-bullets would make Requirement R1 unmanageable and extremely difficult to measure. No change made. The SDT believes the suggested language does not provide any additional clarity. No change made. R2 & R3 - No justification for including the Reliability Coordinator was provided and the SDT sees no reliability reason to include the Reliability Coordinator in this process. No change made.		
Arizona Public Service Company	No	The need for the proposed "overarching" document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
Response: There is no mandate for an "overarching" document. The requirement is to provide document for any data that is needed for reliability. No change made.		
U.S. Bureau of Reclamation	Ballot Comment	The term "required" in requirement R1 "Each Transmission Operator and Balancing Authority shall have create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring." is not defined and does not encourage coordination amond the entities. It is suggested that coordination would be encouragedif an impartial entity provided oversight. The following language would resolve the undefined term and encourage coordination. "Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring as required by the requirements in the NERC Reliability Standards. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. 1.2. A mutually agreeable format. 1.3. A periodicity for providing data. 1.4. The deadline by which the respondent is to provide the indicated data. 1.5. The specific NERC Reliability Standard requirement for which the data is needed. R5. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification will notify the Reliability Assurer if the data specifications are not consistent with

Organization	Yes or No	Question 3 Comment
		the NERC Reliability Standard Requirements. R6. The Reliability Assurer will review the data specifications for consistency with the NERC Reliability Standards and notify the Transmission Operator and Balancing Authority of the results and changes if any that are needed."
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its real time analysis, then no documentation specification is needed. However, when data is required, than a formal specification is mandated so that the entity receiving the request "knows" what is being requested. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made. Expanding a requirement to include procedural items does more to limit the flexibility and utilization of new technologies than it does to improve data exchange of current technologies. The two bulleted items under R1.1 of TOP-003-1 will be removed in the next posting. There are no data requirements in the current standards that cover the items in each and every analysis tool. Moreover, the current Reliability Standards Development process requires that all mandates be in the standard requirements themselves and not left as a fill-in-the-blank measure as defined by the subjectivity of a Reliability Assurer. No change made.		
NorthWestern Energy	Ballot Comment	TOP-003-2 We disagree with the new proposed version of the standard; the requirements obligate the Transmission Operator and Balancing Authority to create documented specifications for the data necessary to perform required Operational Planning Analysis and Real-time monitoring. This data is already spelled out and identified in the current version of TOP-003-1. The data requirements in the current standard TOP-003-1 have been tested and have been proven to be effective in gathering necessary data required by TOPs and BAs. The new proposed TOP-003-2 places a greater burden and responsibility on TOPs and BAs. If something is missed in the newly created specification for data necessary to perform Operational Planning Analysis, the responsibility falls on the TOP or BA alone.
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. No change made. If something is missed in the specification, the SDT believes that the onus should be on the Transmission Operator or Balancing Authority. The data requirements are thus defined by the Transmission Operator and not by an auditor. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for		

Organization	Yes or No	Question 3 Comment
not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made.		
Lakeland Electric Beaches Energy Services	No	TOP-003-3: R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced, and will probably be perceived by FERC as being too flexible a requirement that would allow a TOP or BA to do less than they are currently required. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards to at least prove to FERC that we are not subtracting data/information requirements. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: 1. Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...." The second use of Facilities in the phrase ought to be deleted (see below), or at minimum, replaced with the term Elements. 2. Although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 “mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. Suggest clarifying who is mutually agreeing. Also, from reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity’s data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		

Organization	Yes or No	Question 3 Comment
Mutually agreeable format is between the requesting entity and the entity being requested. As has been cited in previous posting comment responses, the SDT believes that the entities involved will be reasonable in approaching a solution to a problem. However, if a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made. This standard requires that data be requested when needed and that all parties come to a reasonable solution. If a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made.		
Progress Energy	No	We perform many studies in different time frames that could be viewed as an "Operational Planning Analysis", from seasonal assessments, to OPC studies, to outage planning studies, day-ahead planning studies, real-time CA studies, etc. Our question is, which of these studies will be subject to all of the requirements in TOP1, 2, 3, and particularly to the data specification requirements in TOP-003? Will Transmission Operators be expected to meet these requirements for ALL studies, or can we designate one specific study process as the "Operational Planning Analysis" study (and, by implication, exempt others from the requirements). Also, TOP-003, R1 also includes "real-time monitoring" in the scope of the requirement for the data specification, so does this include the EMS and all of its data? This would require multiple data specifications, because the EMS and off-line PSS/E models we use to perform various studies would require different data specifications, have different contacts that provide information, etc.
Response: The commenter's first question is concerned about an auditor making the decision about what data must be specified. The word "required" is used in Requirement R1 specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its Real-time analysis then no documentation specification is needed. However, when data is required for "any" of its analysis programs, then a formal specification is mandated so that the entity receiving the request "knows" what is being requested. It is up to the Transmission Operator or Balancing Authority to determine what data it needs to perform its studies. In other words, you select what data you need to perform your duties. There is no mandate for data specifications for data that a Transmission Operator already has. The standard does not specify which tools are considered as monitoring tools. If the EMS is defined as your monitoring tool then whenever additional data is needed, this standard requires the Transmission Operator to formally ask an entity for that data in the form and the time frame needed. The concern that a Transmission Operator will be found non-compliant because there is no one single document that covers all data is a misplaced concern. This requirement is written to be forward looking, not looking backward.		
City of Tallahassee	Ballot Comment	While it specifies that the examples are only possibilities for evidence, the inclusion of "with acknowledgement" to "web postings" in M2 & M3 for TOP-003-2 will become onerous. It

Organization	Yes or No	Question 3 Comment
		requires another entity to respond in order to have evidence we were compliant.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
Luminant Energy	No	While we agree with the concept of the TOP and BA creating a specification for data necessary for Operational Planning and Real-time monitoring, we feel that Requirement 1.2 should explicitly state that the format should be mutually agreeable to the TOP and BA and the parties receiving the data request under R2 and R3. Additionally, for R1.3, we feel the same mutually agreeable requirement between the TOP and BA and the parties receiving the data request should be added for the periodicity requirement.
Response: Mutually agreeable format is between the requesting entity and the entity being requested. The SDT believes this is clear with the existing wording. This applies to the periodicity element as well. No change made.		
American Electric Power	Yes	Additional clarity is needed as to the type(s) of data that would be considered necessary for performing operational planning analysis and real time monitoring. For example, will the requirements as specified in attachment 1 for TOP-005-2 be incorporated into TOP-003-1?
Response: Requirement R1 is actually quite specific – the data specification will include any and all data needed by a Transmission Operator or a Balancing Authority to fulfill their responsibilities. If the data is not on the list, then the data need not be supplied. However, the SDT has made clarifying changes to Requirements R2 & R3 that address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Northeast Utilities	Yes	Editorial comment: Remove "M5" because there is not any corresponding text and there is not a corresponding R5.

Organization	Yes or No	Question 3 Comment
Response: Agreed.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities believes the question should be directed toward TOP-003-2.
Bonneville Power Administration	Yes	
Western Electricity Coordinating Council	Yes	
Southern Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The SDT made some changes to the VRFs, VSLs, and Time Horizons based on feedback received. Because these are compliance elements, they are not viewed as substantial changes to the standards.

One commenter requested a time frame for failing to inform per TOP-001-2, Requirement R2. The SDT made no change because each situation is different, preventing a universal time frame to inform.

The VSLs for TOP-001-2, Requirements R3, R5, and R6, TOP-002-3, Requirement R3, and TOP-003-2, Requirements R2 and R3, were modified to remove percentages. Some commenters found them confusing with both integer and percentage values. The sample sets are expected to be small enough that percentages will not work well.

The VSLs for TOP-001-2, Requirement R6 were further clarified to eliminate confusing language.

Several commenters expressed that VRFs, VSLs, and Time Horizons were not ready to be balloted until the requested changes to other parts of the standard were made. With the need to employ a successive ballot, this becomes a moot point.

Some commenters expressed that the High VRF associated with requirements to operate within the subset of non-IROL SOLs required to be identified per TOP-001-2, Requirement R8 should be changed to a Medium VRF. The SDT felt because these SOLs are viewed as being so important that a Transmission Operator must inform the Reliability Coordinator of them that the associated requirements warrant a High VRF as these SOLs are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined T_v, but must respect the Facility Rating or Stability criteria upon which they are based.

The Moderate and High VSLs for TOP-001-2, Requirement R8 were modified by changing the “or” between the ranges to an “and”. “Local” was replaced with “internal” for all of the VSLs to be consistent with the requirement.

Operations Planning and Same-day Operations were added to the TOP-001-2, Requirement R8 time horizon.

The VRF for TOP-002-3, Requirement R3 was changed to Medium.

For consistency, the VSL for TOP-001-2, Requirement R2 has been modified to match the language of the requirement more closely.

TOP-003-2, Requirement R1 VSLs were modified to include additional gradations for missing three and four or more parts of the requirement.

Several commenters were concerned about escalation of the VSLs associated with TOP-003-2, Requirement R4 for missing a few pieces of data. One even suggested the data should be prioritized based on unit size. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc., and no change was made. One commenter was concerned that VSLs for TOP-001-2, Requirement R6 do not consider small entities and suggested prioritizing of the VSLs based on unit size. The SDT believes VSLs do consider the impact on small entities. The SDT did not make any changes to prioritize the VSLs based on unit size because that is only applicable for adequacy and unit size is not relevant for transmission security.

One commenter requested the TOP-001-2, Requirement R1 Severe VSL should use an "or" condition rather than the "and" condition for failing to follow a directive and informing of the reason for not following the directive. The SDT felt the "and" condition was appropriate.

One commenter suggested that TOP-001-2, Requirement R6 was fundamentally modified to include data when telemetering equipment was changed to telemetry. The SDT agreed and modified the requirement accordingly.

TOP-001-2, R8: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

TOP-002-3, R3: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*

TOP-001-2, R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that

				Transmission Operator.

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	1. The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 2. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.

TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	3. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 4. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.

		area reliability.	area reliability.	

TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).

TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	5. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 6. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
City of Tacoma or Tacoma Public Utilities	No	1. TOP-001-2: In general, when “failure to inform” results in VSL, the timeframe for informing needs to be defined. 2. TOP-002-3, R3: The VSL language for all levels is confusing. At the minimum, the percentages for should be consistent between Lower, Moderate, High and Severe. 3. TOP-003-2: Similar to TOP-002-3, the VSL language for all levels is confusing and should be consistent between VSL levels.

Response: 1) The SDT disagrees with establishing a uniform time frame for response as each situation will be different. No change made.

2) and 3) The SDT concurs and has clarified the language.

TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 4 Comment
Duke Energy Carolina	Ballot Comment	4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that

Organization	Yes or No	Question 4 Comment
		alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs. 5.
Duke Energy	No	Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs.
Response: Please see the SDT response to the “supporting local area reliability” issue in the associated comments for Q1.		
Ameren	No	As stated in comments above, we have concerns about the newly introduced term “internal” area reliability in TOP-001 and TOP-002 and proposed Medium VRF to the corresponding requirements.
Response: Please see our comments regarding the “internal” area reliability issue in the responses to Q1. The SDT believes the Medium VRF is appropriate as the SOLs that are identified by the Transmission Operator are important SOLs. No change made.		
Florida Municipal Power Agency	No	FMPA has no comments on the VRFs FMPA believes significant changes to the standards are

Organization	Yes or No	Question 4 Comment
		required; hence, it is too early to opine on the VSLs.
FirstEnergy	No	We cannot support the current VSL until our suggested changes to the requirements are made.
Response: Thank you for your response.		
Northeast Utilities	Yes	For TOP-001-2 Requirements R3, R5, R6 and R8, suggest changing "or' to "and" - that is change “...more than x% OR less than or equal to y%...” to “...more than x% AND less than or equal to y%...”
Northeast Power Coordinating Council Independent Electricity System Operator Hydro One Networks Inc	No	Referring to the Moderate and High VLSs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VLSs state “...more than x% or less than or equal to y%...”, suggest changing to ““...more than x% and less than or equal to y%...”. These changes would also make these VLSs consistent with the language of TOP-002-3 and TOP-003-2.
Response: For Requirements R3, R5, and R6, the SDT decided to eliminate percentages in favor of integer VSL levels given the sample set sizes will likely be small even for a large Transmission Operator.		

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission	The Transmission Operator did not inform two other Transmission	The Transmission Operator did not inform three other Transmission	7. The Transmission Operator did not inform its Reliability Coordinator of

Organization			Yes or No	Question 4 Comment
	Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 8. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment,	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of	9. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and

<table>
<tr><th colspan="3">Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td>control equipment, and associated communication channels between the affected entities.</td><td>equipment,control equipment ,and associated communication channels between the affected entities.</td><td>telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.</td><td>associated communication channels.
10. OR,
The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.</td></tr>
<tr><td colspan="5">For Requirement R8, the recommended change was made and the percentage VSLs were retained as there is more uncertainty over the sample set sizes for this requirement.</td></tr>
<tr><td colspan="3">Puget Sound Energy</td><td>No</td><td>In TOP-001-2, R8, the time horizon should include Operations Planning and Same-day Operations, in addition to the currently-listed Real-Time Operations.
In TOP-002-3, R3, the VRF is listed as “High”. However, according to the document “Violation Risk Factor and Violation Severity Level Assignments”, the appropriate level is “Medium”, which is also more consistent with the assignments associated with other requirements throughout these proposed standards.
In TOP-002-3, the VSL matrix</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		entries associated with R3 need to have additional references to “reliability entities” changed to “registered entities”.
Response: The SDT has made the suggested changes to TOP-001-2, Requirement R8 and TOP-002-3, Requirement R3. **TOP-001-2, R8**: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]* For the TOP-002-3, Requirement R3 VSL, no change was made because the VSLs already used the term registered entities as requested.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:TOP-001-2 VSLs1. VSL for R2a. The word “comply” is not within the language of R2 and should be removed from the VSL. R2 simply requires the Applicable Entities to “... inform its Transmission Operator...”. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” 2. VSL for R8a. The term “local area reliability” should

Organization	Yes or No	Question 4 Comment
		be replaced with "internal area reliability" to be consistent with the language in R8. This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement"TOP-003-21. VSL for R1a. The sub-parts should be referenced in the VSL. (i.e. "The responsible entity did not include one of the required elements, per Requirement R1, Parts 1.1 though Parts 1.4, of the documented specification...") b. There is no provision if an Applicable Entity fails to include three or more of the required elements. VSLs should be gradated to include failure of including both three and four sub parts.

Response: The SDT does not believe any of the VSLs referenced are in violation of FERC guideline 3. The VSLs do not have to use the exact language of the requirement to be consistent. However, the SDT does recognize there is value in using the same wording to the extent possible for consistency. For TOP-001-2, Requirement R2, the SDT has modified the VSL to use language that is more consistent with the requirement.

For TOP-001-2, Requirement R8, the SDT has replaced local area reliability with internal area reliability for the VSL.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less,

Organization					Yes or No	Question 4 Comment
	IROL, has been identified by the Transmission Operator as supporting its internal area reliability.	whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.	Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.	which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.		
For TOP-003-2, Requirement R1, the VSLs do include the sub-parts. However, they were not fully gradated and the SDT has added VSLs for missing three and four elements.						
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	11. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 12. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.		
LG&E and KU Energy PPL Supply					No	The Time Horizons seem to be inconsistent with established NERC definitions. The VSLs need to be updated with language modified in the requirements
Response: Without additional specificity on Time Horizons, the SDT is unable to make any changes.						

Organization	Yes or No	Question 4 Comment
For the VSLs, the SDT has made numerous changes as specified in other comments.		
Western Electricity Coordinating Council Imperial Irrigation District Arizona Public Service Company	No	These same comments were submitted with our vote on the non-binding VRF and VSL pollWECC agrees with the VRFs and the majority of the VSLs. However, we beleive consideration of the following will improve the VSLs.TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning

Organization	Yes or No	Question 4 Comment
		Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?

Response: For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	13. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 14. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated

Organization			Yes or No	Question 4 Comment
				communication channels between the affected entities.
For TOP-003-2, Requirement R1 VSLs, the SDT has added VSLs for missing three and four or more elements.				
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	15. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 16. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.
TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.				
Indeck Energy Services			No	TOP-001-2 R6: The VSL's do not consider the case of a small GOP (and possibly DP or LSE) which only affects the TOP or BA. The VSL needs

Organization	Yes or No	Question 4 Comment
		to reflect the significance of the planned outages. Planned outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Planned outages on GOP facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable Disturbance would be Medium and all others would be Lower. TOP-003-2 R4: Only having Severe VSL avoids the difficult process of deciding what data is important. Data on outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Data on facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable

Organization	Yes or No	Question 4 Comment
		Disturbance would be Medium and all others would be Lower.
Response: For TOP-001-2, Requirement R6, the SDT did attempt to address the case of the small Generator Operator, Transmission Operator or Balancing Authority by including the "x negatively impacted interconnected NERC registered entities".. It did not attempt to address small Distribution Providers or Load-Serving Entities as the requirement does not apply to them. While it may be true that wind projects are of lower significance to adequacy than base load units, the SDT did not make any changes based on the size of the unit as the size of the unit may not be relevant to its importance to the transmission security of reliability. TOP-003-2, Requirement R4: All data can be important given the right circumstances. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Colorado Springs Utilities	No	TOP-001-2 R8 & R9 VRFs should be "Low"TOP-002-3; R2 - IROLs should be "High" / SOLs should be "Low". R3 should be "Medium".
Response: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirements R8 and R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. Thus, the VRFs for TOP-002-3, Requirement R2 were not changed. The SDT had modified the VRF for TOP-002-3, Requirement R3 to Medium. **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*		
Bonneville Power Administration	No	TOP-003-2: The proposed

Organization	Yes or No	Question 4 Comment
		sanctions seem disproportionate to the offense. If a BA fails to contact an entity that influences its operation, the failure does not seem to affect anything except the evaluation's accuracy to the offending BA. Furthermore, it seems unlikely that a deliberate omission would be made since it's in a BA's best interest to have accurate assessments. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the

Organization	Yes or No	Question 4 Comment
		documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?

Response: TOP-003-2: The SDT is unsure of the specificity of your first comment. If you are referring to the percentage thresholds escalating quickly with 5% increments, these have been removed in favor of integer values.

TOP-001-2, Requirement R6: The SDT agrees with your comment and has made clarifying changes.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	17. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 18. OR, The responsible entity did not notify four or more

Organization			Yes or No	Question 4 Comment
	entities.	affected entities.	entities.whichever is less.	negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
TOP-003-2, Requirement R1: The SDT agrees with your comment and has added VSLs for missing three and four or more elements.				
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	19. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 20. 21. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.
TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent				

Organization	Yes or No	Question 4 Comment
failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Southern Company	Yes	(Please note that these comments relate to TOP-001-2). It is suggested that the R1 VSL Severity text be written as an either/or statement. "entity either did not comply with (a directive) or did not inform ....”R1, as its currently written, gives an entity these two choices. The R2 VSL Severe test is more expansive than Requirement 2. To match R2, it is suggested that the test read" ...entity did not inform the TOP of its inability to comply" The R6 graduated VSLs, as written, are hard to understand. For a given outage, it is unclear how many "affected entities" there are likely to be. Also for R6, the OR statement has conflicting scope (i.e. planned outage of telemetry OR with planned outage of telemetering equipment).
Response: No change was made to TOP-001-2, Requirement R1 Severe VSL because the "and" condition is appropriate. If the responsible entity does not comply it must also inform the Transmission Operator. With an "or" condition, failure to comply would be a Severe VSL even if the responsible entity informs the Transmission Operator. The SDT agrees with your assessment for the VSL for TOP-001-2, Requirement R2 and has modified it.		

Organization			Yes or No	Question 4 Comment
TOP-001-2, R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.				
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	22. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 23. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R6: The SDT agrees with your comment. Consistent with your comments in Question 1, the SDT changed telemetry to telemetering equipment.				

Organization	Yes or No	Question 4 Comment
Luminant Energy	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings Inc	Yes	
Cowlitz County PUD	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The comments in this section are mostly repeats of comments submitted for other questions. No changes were made to requirements for comments made exclusively for this question.

Organization	Yes or No	Question 1 Comment
NIPSCO		The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES distribution facilities into play.
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. No change made. The bullets in TOP-003-2 have been deleted.		
Imperial Irrigation District		1. The proposed versions of the standards appear to remove the redundancy and provide better clarity to the requirements. However the period when the proposed standard becomes effective is cumbersome.PROPOSED - Suggest two effective dates be provided? For example:Regulatory approval 05/01/2011Effective Date 10/01/2013Effective Date “Not Requiring Regulatory Approval” 10/01/2013CURRENT - Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption. 2. Recommend that the RSAWS for these proposed standards be revised and posted when the standard versions become effective. 3. Data Retention - Could the Data Retention be displayed in a matrix format (see example below) EXAMPLE Function Requirement Evidence Retention Period TOP R1 Compliance with RC Directives Current Year + Previous Year BA R2 Compliance with TOP Directive Current Year + 1 Year GOP R3 Compliance with TOP Directive

Organization	Yes or No	Question 1 Comment
		Current Year + 1

Response: The effective date language used is provided by NERC Legal and is not subject to change by an SDT. No change made.

RSAWs are not within the scope of the SDT. They are a compliance item.

The format shown for data retention is supplied by the template used by SDTs. The SDT did not receive any other comments in this regard and is reluctant to change the format at this point in time. The SDT suggests that you send your request for a different data retention format to the NERC Standards Process Manager for consideration. No change made.

Organization	Yes or No	Question 1 Comment
City of Tacoma or Tacoma Public Utilities		Comments: Please provide the definitions for new terms in the first version of the Standards. Once they have been introduced and/or the standard is undergoing a new revision - they could be removed to the Glossary for future reference.

Response: The only new term used in the standards is Reliability Directive and that is supplied with the document. No change made.

Organization	Yes or No	Question 1 Comment
Arizona Public Service Co.	Ballot Comment	The need for the proposed “overarching” document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.

Response: There is no mandate for an “overarching” document. The requirement is to provide document for any data that is needed for reliability. No change made.

Organization	Yes or No	Question 1 Comment
Wisconsin Energy Corp.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse

Organization	Yes or No	Question 1 Comment
		Reliability Impact on another's area, hence an emergency there is somewhat circular. TOP-002 R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered. TOP-003 R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.

Response: TOP-001, R3: The requirement is referring to transmission problems so the Balancing Authority doesn't have to be notified. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT has deleted Generator Operator from this requirement.

R10: This is a transmission function and not within the purview of the Balancing Authority so there is no need to notify them. No change made.

R3 & R5: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

TOP-002, R3: The SDT has added the qualifier 'NERC' to the requirement to provide additional clarity.

TOP-003, R2 & R3: The Transmission Operator or Balancing Authority will only be requesting data from those it needs it from which will include all entities monitoring the equipment that the Transmission Operator or Balancing Authority is interested in. The SDT does not see any problem with the current language. No change made.

R4: The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.

END OF REPORT