Consideration of Comments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

The Project 2014-03 Drafting Team (SDT) thanks all commenters who submitted comments on the TOP/IRO Reliability Standards. These standards were posted for a 45-day public comment period from August 6, 2014 through September 19, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 59 sets of comments, including comments from approximately 166 different people from approximately 95 companies representing 8 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 standards' project page.

Summary Consideration:

The SDT appreciates the careful review stakeholders provided of this large volume of standards and thanks stakeholders for their support in completing this project. The SDT has made a number of changes to each of the standards in response to stakeholder comments.

TOP-001-3 was the only standard requiring substantive changes, as well as a number of clarifying changes, in response to stakeholder comments. The SDT made the following changes to proposed TOP-001-3:

- Deleted *Operations Planning* time horizon from all requirements dealing with Operating Instructions
- Requirements R1 and R2 – changed 'ensure' to address'; clarified language on actions and issuance of Operating Instructions
- Requirement R7 – capitalized 'E' in Emergency
- Requirement R8 – deleted 'other'
- Requirement R9 – added 'sustained' to outages; deleted 'NERC registered'; merged 'telemetering and control'
- Requirement R10 – completely restructured for clarity on what needs to be monitored
- Requirement R11 – replaced 'ensure'
- Requirement R15 – grammatical changes
- Requirement R16 – Changed 'Real-time Assessment' to 'analysis'
- Requirement R18 – deleted 'Balancing Authority'; deleted 'always'
- Requirements R19 and R20 – corrected typographical errors

In response to stakeholder comments, the SDT has made only clarifying and non-substantive changes to the other eight standards, as follows:

- IRO-001-4
  - Deleted *Operations Planning* time horizon from all requirements dealing with Operating Instructions
  - Requirement R1 - changed 'ensure' to 'address;' clarified language on actions and issuance of Operating Instructions
  - Measure M2 – deleted 'Transmission Service Provider' to conform to Requirement R2
  - Data retention – deleted 'Transmission Service Provider' to conform to Applicability
- IRO-002-4
  - Requirement R1 – made grammatical change
  - Requirement R3 – replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- IRO-008-2
  - Requirement R3 – made grammatical changes
  - Requirement R5 – deleted 'Reliability Coordinator' from 'Wide Area'
  - Requirement R6 – corrected typographical error
- IRO-010-2
  - Requirement R1, Part 1.1 – replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- IRO-014-3
  - Measure M1 – added 'may' impact
  - Requirement R5 – corrected tense
  - Requirement R6 – corrected tense
  - Data retention – corrected requirement numbering
- IRO-017-1
  - Requirement R1, Part 1.3 – replaced 'generator' with 'generation'
  - Requirement R2 – made 'entity' plural
  - Requirement R3 – changed time horizon from 'Operations Planning' to 'Long-term Planning'
- TOP-002-4
  - Measure M2 – added 'exceedances' term
  - Requirements R3 and R5 – deleted 'impacted'
- TOP-003-3
  - Requirement R1, Part 1.1 - replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- SOL Exceedance White Paper
  - Made several clarifying changes
- Violation Severity Levels
  - IRO-008-2, Requirement R3 – deleted NERC registered;' changed 'less than' to 'greater than;' made grammatical change
  - IRO-008-2, Requirement R4 – deleted first part of Severe VSL

- IRO-014-3, Requirement R2 – changed 'address' from 'meet;' changed from 'criteria' to 'parts'
- IRO-014-3, Requirement R7 – corrected tense of verbs
- IRO-017-1, Requirement R2 – changed entity to plural in Severe VSL
- TOP-001-3, Requirements R1 and R2 – restructured language to match requirement
- TOP-001-3, Requirement R7 – corrected grammatical errors
- TOP-001-3, Requirement R8 – deleted 'whichever is less;' deleted 'other'
- TOP-001-3, Requirement R9 – deleted 'whichever is less'
- TOP-001-3, Requirement R10 – changed from binary approach to incremental approach
- TOP-001-3, Requirement R13 – corrected numeric error in Severe VSL
- TOP-002-4, Requirement R3 – corrected 'NERC entities' language
- TOP-002-4, Requirement R5 – deleted 'impacted;' changed 'less than' to 'greater than'
- TOP-003-3, Requirement R5 – added Lower VSL; deleted first part of severe VSL

The SDT is recommending that proposed TOP-001-3 be posted for an additional comment period and ballot, and that the other standards, definitions, and Implementation Plan be posted for final ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

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	Ben Engelby	ACES Standards Collaborators	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 5
2.	Ginger Mercier	Prairie Power, Inc.	SERC	3
3.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

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

Additional Member	Additional Organization	Region	Segment Selection	
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat G Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5

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

Additional Member	Additional Organization	Region	Segment Selection	
1.	Steve Hitchens	Technical Operations	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Berhanu Tesema	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
5.	Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Doug Hils			1
2.	Lee Schuster			3
3.	Dal Goodwine			5
4.	Greg Cecil			6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4

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

2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Randy Hahn	Ocala Utlity Service	FRCC	3
6.	Don Cuevas	Beaches Energy Services	FRCC	1
7.	Stan Rzad	Keys Energy Services	FRCC	4
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
10.	Steve Lancaster	Beaches Energy Services	FRCC	3
11.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
12.	Mike Blough	Kissimmee Utility Authority	FRCC	5

				1	2	3	4	5	6	7	8	9	10
7.	Group	Greg Campoli	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ben Li	IESO	NPCC	2
2.	Charles Yeung	SPP	SPP	2
3.	Matt Goldberg	ISO-NE	NPCC	2
4.	Terry Bilke	MISO	RFC	2
5.	Ali Miremadi	CAISO	WECC	2

				1	2	3	4	5	6	7	8	9	10
8.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2

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

11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Randi Heise	NERC Compliance Policy	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Garton	Dominion	NPCC	5
2.	Connie Lowe	Dominion	RFC	6
3.	Louis Slade	Dominion	SERC	2, 5
4.	Chip Humphrey	Dominion	RFC	5
5.	Latrry Nash	Dominion	SERC	1, 3
6.	Sandra Hopkins	Dominion	SERC	6
7.	Jeffrey N. Bailey	Dominion	NPCC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent 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.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2

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

12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Robert Rhodes	SPP Standards Review Group	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Bensky	ITC Holdings	SPP	1
2.	Kaleb Brimhall	Colorado Springs Utilities	WECC	1, 5, 6
3.	Michelle Corley	Cleco Power LLC	SPP	1, 3, 5, 6
4.	Dave Dieterich	Omaha Public Power District	MRO	1, 3, 5
5.	Neal Faltys	Omaha Public Power District	MRO	1, 3, 5
6.	Todd Gosnell	Omaha Public Power District	MRO	1, 3, 5
7.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5, 6
8.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
9.	Vinit Gupta	ITC Holdings	SPP	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Jonathan Hayes	Southwest Power Pool	SPP	2									
11.	Robert Hirchak	Cleco Power LLC	SPP	1, 3, 5, 6									
12.	Brett Holland	Kansas City Power & Light	SPP	1, 3, 5, 6									
13.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5									
14.	Thomas Mayhan	Omaha Public Power District	MRO	1, 3, 5									
15.	Gregory McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5, 6									
16.	Shannon Mickens	Southwest Power Pool	SPP	2									
17.	Mike Moltane	ITC Holdings	SPP	1									
18.	James Nail	City of Independence, MO	SPP	3, 5									
19.	Si Nguyen	Omaha Public Power District	MRO	1, 3, 5									
20.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5, 6									
21.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5									
22.	Jon Shipman	Omaha Public Power District	MRO	1, 3, 5									
23.	Josh Verzal	Omaha Public Power District	MRO	1, 3, 5									
13.	Individual	David Jendras	Ameren	X		X		X	X				
14.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
15.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
16.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
17.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X							
18.	Individual	Scott Langston	City of Tallahassee	X									
19.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
20.	Individual	Jack Stamper	Clark Public Utilities	X									
21.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
22.	Individual	Eric Sutlief	Consumers Energy Company			X	X	X					
23.	Individual	Glenn Pressler	CPS Energy	X		X		X					
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Russell Schneider	Flathead Electric Cooperative, Inc.			X	X						
26.	Individual	Scott Knewasser	FRCC Compliance										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	John A. Libertz	FRCC Operating Committee (Member Services)	X									
28.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
29.	Individual	Daniel Mason	HHWP					X					
30.	Individual	Ayesha Sabouba	Hydro One	X		X							
31.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
32.	Individual	Dave Willis	Idaho Power Company	X									
33.	Individual	Leonard Kula	Independent Electricity System Operator		X								
34.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
35.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration , LP					X					
36.	Individual	Michael Moltane	ITC	X									
37.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
38.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
39.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
40.	Individual	Terry Harbour	MidAmerican Energy Company	X									
41.	Individual	Gregory Campoli	New York Independent System Operator (NYISO)		X								
42.	Individual	Bill Temple	Northeast Utilities	X									
43.	Individual	Robert Fox on behalf of David Austin	Northern Indiana Public Service Company (NIPSCO)	X		X		X	X				
44.	Individual	Rich Salgo	NV Energy	X		X		X					
45.	Individual	Joshua Smith	Oncor Electric Delivery LLC	X									
46.	Individual	Sandra Shaffer	PacifiCorp						X				
47.	Individual	Jared Shakespeare	Peak Reliability	X									
48.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
49.	Individual	Catherine Wesley	PJM Interconnection		X								
50.	Individual	Denise M. Lietz	Puget Sound Energy	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	Anthony Jablonski	ReliabilityFirst										X
52.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
53.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
54.	Individual	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
55.	Individual	Joel Wise	Tennessee Valley Authority	X		X						X	
56.	Individual	Karin Schweitzer	Texas Reliability Entity										X
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Steve Johnson	Western Area Power Administration	X		X							
59.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				

1. **Do you agree with the changes made to respond to industry comments to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes**.

Summary Consideration: The SDT deleted 'Operations Planning' from all time horizons concerning Operating Instructions as Operating Instructions are issued in Real-time environments.

R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

1.3. Data Retention

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Organization	Yes or No	Question 1 Comments
ACES Standards Collaborators	No	(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) Requirement R1 should be revised by removing the words "direct others to act" and stating that the RC shall issue Operating Instructions. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and

Organization	Yes or No	Question 1 Comments
		may not fully capture what the drafting team is trying to achieve. For example, by stating that the RC shall act or direct others to act by issuing an Operating Instruction, the RC is limited only to this option. We recommend alternative language for this requirement, “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” (3) Requirement R1’s language of requiring the RC to “ensure reliability” could be used as a zero defect standard if there is an event. “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” (4) The rationale for requirements R2 and R3 contradict with the revisions to the requirements. The rationale states that the TSP was added to allow retirement of IRO-004-2, but the draft removes the TSP from the requirements. Is the intent to keep IRO-004-2 intact? (5) Requirement R3 should be merged with R2. We suggest the following language for consideration, “Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Reliability Coordinator, or shall inform its Reliability Coordinator of its inability to perform because it cannot be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements.” This revision captures the intent of both requirements, is consistent with TOP-001, and reduces the amount of requirements needed. It also reduces unnecessary compliance exposure since only one violation could occur rather than potentially two requirements being violated.

Response: 1. Thank you for your support.

2. The SDT agrees and has revised the wording of the requirement. See summary for wording.
3. The SDT has revised the requirement to delete ‘ensure’ and replace it with ‘address’ as in the first posting. See summary for wording.
4. The SDT agrees and has corrected the language in the rationale box.
5. The SDT believes both requirements are needed independently and combining them using the proposed language creates essentially two requirements in one which should be avoided. No change made.

Organization	Yes or No	Question 1 Comments
Georgia Transmission Corporation	No	(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) The current proposal for R2 as written could overly expose the DP to excess and double jeopardy compliance obligations for routine switching operations DPs perform on a daily basis which does not affect the reliability of the BES. Daily switching which require Operating Instructions could include scheduled outages for maintenance items and new construction. The functional model clearly states that RCs "...Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators". Based on this, one could assume the Operating Instruction issued by an RC to a DP would be limited to a load shedding scenario and not daily switching routines mentioned above. However, this arrangement becomes less clear when the issuer of the Operating Instruction has multiple registrations with NERC as the RC, BA, and TOP; and when the recipient of the operating instruction is registered with NERC as a DP, TO, and TSP. Under such exchange, a single Operating Instruction issued from such an entity is technically an Operating Instruction from the RC, BA, and TOP; the recipient of this single Operating Instruction also applies to each of their registration type being a DP, TO, and TSP. To the auditor, this single Operating Instruction could be the same piece of evidence for multiple requirements across multiple Standards such as IRO-001 and TOP-001. GTC believes the RC to DP interaction (with the RCs wide area view) is limited to Emergency scenarios which warrant a separate requirement for clarification of such exchange. A separate requirement for the DP is also justified and helps the ambiguity surrounding Real Time vs Ahead of Time activities within scope of the RC. The RC could issue Operating Instructions to the TOP, BA, GOP and IA for both Real Time and Ahead of Time, but GTC believes the DP is limited to Real Time horizon associated with "load shed" only in order for the RC to ensure the reliability of its Reliability Coordinator Area. A standalone requirement would correct the ambiguity expressed above and would more accurately capture the scenario of when the RC would be issuing Operating Instructions to the DP rather than BA, TOP, GOP, etc. Again, GTC's goal is for

Organization	Yes or No	Question 1 Comments
		this requirement not to overlap on the daily switching routines performed by the DP which require Operating Instructions such as scheduled outages for maintenance items and new construction when the issuing entity has both registrations of RC and TOP.GTC proposes the following standalone requirement for the DP: "Each Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions associated with load shed unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements." Alternately, GTC would accept "Each Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions during an Emergency unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements."
Response: 1. Thank you for your support. 2. The SDT agrees that Operating Instructions from the Reliability Coordinator to the Distribution Provider would most likely be limited to a Load shedding scenario; however the SDT does not believe a separate requirement for Reliability Coordinator to Distribution Provider communication is needed because the current wording in Requirements R2 and R3 covers this communication. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. The term Operating Instruction is defined as a command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.) Because the definition of Operating Instruction is focused on real-time activities necessary to preserve the real-time status and condition of the BES and indicates that such activities may only be issued by operating personnel responsible for the Real-time operation of the BES, ERCOT suggests that the use of the term Operating Instruction within the multiple time horizons referenced throughout IRO-001-4 (especially the operations

Organization	Yes or No	Question 1 Comments
		planning and same-day operations time horizons) undermines the objectives of issuing Operating Instructions in Real-Time, are likely to cause confusion regarding the Operating Instruction an entity should implement, and would result in significant resource and operational concerns. First, because the term Operating Instruction as developed and utilized in COM-002-4 is intended to provide operating personnel responsible for the real-time status and condition of the BES with additional tools and authority to prevent miscommunications and ensure the reliability of the BES, its definition has been tailored to real-time scenarios and responsibilities. Indeed, the very definition is focused on responding to emerging conditions within the BES to ensure reliability, connoting urgency and ensuring that the issuer's authority and direction is unchallenged and timely implemented. This sense of urgency and authority that provided additional strength to Reliability Coordinators in fulfilling obligations under COM-002-4 is weakened significantly when the term Operating Instruction is applied to activities expected to be performed days in advance of target operating day. Specifically, because the activities identified as mitigations to forecasted system conditions are based on forecasts and best available information in advance of the actual operating day, such conditions may never manifest themselves and the "command" issued may never need to be implemented. Accordingly, the use of the term Operating Instruction within Same-Day and Operations Planning Horizons is likely to cause confusion as the directed activities may never need to be taken, but would essentially be defined through the use of the term Operating Instructions, as "urgent" actions. Additionally, entities being issued advance "Operating Instructions" may become confused regarding what activities they should perform if Operating Instructions devised as a result of a Next-Day Study differed from the Operating Instructions received in Real-Time. Generally, actions in advance of the target operating day are coordinated amongst impacted entities with the objective of ensuring that operating parameters are respected should adverse conditions manifest during the target operating day. These activities are generally plans that are developed prior to the target operating day in response to forecasted conditions. As discussed earlier, the term Operating Instruction was devised to provide Reliability Coordinators and other responsible entities with the tools and authority necessary to

Organization	Yes or No	Question 1 Comments
		proactively ensure the reliability of the BES in real-time. Plans developed in response to forecasted conditions that may or may not manifest themselves are not and should not equated with actions that should be taken immediately to preserve reliability. Finally, ERCOT notes potential resource and operational concerns with requiring Reliability Coordinators to utilize their operating personnel responsible for Real-time activities to issue Operating Instructions that would result from Operational Planning Analyses conducted well in advance of real-time. In particular, because the definition of Operating Instruction requires that such an instruction be issued by operating personnel responsible for the real-time operation of the BES (which is generally interpreted synonymously with "system operator"), ERCOT respectfully submits its significant concerns regarding diverting its real-time personnel and resources to tasks generally performed by personnel focused on the day-ahead or operations planning time horizons. More specifically, Operational Planning Analyses are generally performed by personnel that are not considered operating personnel, but are, rather Operations Support Personnel or other technical personnel. The review, analysis, and final decisions regarding necessary actions, while coordinated with operating personnel, are generally completed and communicated by those same personnel. To issue Operating Instructions for analyses performed in the forward planning horizons would require diversion of operating personnel from their primary tasks in the real-time environment to tasks generally performed by personnel focused on operations planning. ERCOT respectfully submits that such would not only cause resource concerns by diverting real-time personnel from ensuring the reliability of the BES, but would also cause operational concerns as entities receiving such Operating Instructions from personnel that are essentially System Operators may cause confusion regarding when such Operating Instructions should be implemented. To resolve the foregoing concerns, ERCOT respectfully suggests that the Standards Drafting Team (SDT) insert the term "directive" or other verbiage where the use of Operating Instruction is intended to address multiple time horizons until the definition of operating instruction is modified or - should such modification not be possible -permanently (e.g., IRO-001-4, R1, R2, and R3) and coordinated with COM-002-4. As it stands today, applying the term to more than the Real Time horizon will likewise expand the scope of

Organization	Yes or No	Question 1 Comments
		communications that must be addressed in COM-002-4 R1-R3.R1. Each Reliability Coordinator shall act, or direct others to act, by issuing directives or Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] 2. To ensure consistency amongst requirements within the IRO-001-4 standard, it is recommended that Requirement R3 be revised to more closely reflect its triggering or immediately preceding requirement, Requirement R2. The proposed Requirement R3 would read: R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition that the Operating Instruction issued by its Reliability Coordinator pursuant to Requirement 1 cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Additionally, it is recommended that the associated VSL also be modified accordingly.
Response: 1. The SDT agrees with the comments regarding the Operations Planning Horizon and has deleted this horizon from all requirements dealing with Operating Instructions. 2. The SDT believes the current wording in Requirement R3, based on changes made from previous industry comments, clearly states the requirement to inform the Reliability Coordinator if an Operating Instruction cannot be performed. The SDT does not believe the suggested change adds clarity. No change made.		
Associated Electric Cooperative, Inc. - JRO00088 SPP Standards Review Group Kansas City Power & Light	No	AECI agrees with SPP comments regarding R1-R3: R1 - We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Reliability Coordinator takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R1 specifically to those entities identified in Requirements R2 and R3.We recommend the following rewrite: ’Each Reliability Coordinator shall act, or direct others as identified in Requirements R2 and R3 to act, by issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.

Organization	Yes or No	Question 1 Comments
		‘Rationale Box for Requirements R2 & R3 - The Rationale Box for Requirements R2 and R3 does not match the language in the requirements. There is no mention of the Transmission Service Provider in the requirements. It only appears in Measures M2 and M3. The IRO Five Year Review Team had recommended adding Transmission Service Provider to Requirements R2 and R3 to allow the retirement of IRO-004-2. With the removal of the Transmission Service Provider in Requirements R2 and R3, can the retirement of IRO-004-2 move forward?
Response: 1. The SDT has revised the requirement to delete ‘ensure’ and replace it with ‘address’ as in the first posting. See summary for wording. 2. The SDT agrees and has corrected the language in the rationale box.		
Ingleside Cogeneration , LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in IRO-001-4 R2 and R3. In R2/R3, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on IRO-001-4’s requirements to execute an Operating Instruction - and not so much COM-002-4’s oversight of the protocols to use. However, an Operating Instruction can be any communication to “change or preserve the state, status, output, or input” of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to IRO-001-4, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with “this is a mandatory Operating Instruction” should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount

Organization	Yes or No	Question 1 Comments
		of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome - particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.
Response: The SDT believes that complying with Operating Instructions is extremely important for the reliability of the system and that emphasis in audits will be on whether the Operating Instruction was followed as opposed to a missing log entry. The SDT suggests that the commenter's points would be better submitted as comments on the RSAW for proposed IRO-001-4. No change made.		
Flathead Electric Cooperative, Inc.	No	Measures are improved with not having to cite a reason specifically, but still too much evidence burden on the receiving entity. The BA should have recordings already and some of these evidence requirements are duplicative.
Response: The measures provide examples of evidence that may be used to show an entity complied with an Operating Instruction from its Reliability Coordinator. The entity chooses what evidence to provide. No change made.		
Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: "Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure the reliability of its Reliability Coordinator Area." As written, we believe that every communication involving an RC could be considered an Operating Instruction. For example, If a BA/TOP informs the RC of a loss of unit/tripping of equipment and the measures taken to mitigate the situation. Would an RC be required to give Operating Instructions back to the BA/TOP stemming from an informational conversation? We feel the revision adds clarity that the RC will issue Operating Instructions only when they believe it is warranted. R2: No comments M2: All instances of Transmission Service Provider should be removed from this measure.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comments</th></tr>
<tr><td></td><td></td><td>R3: No comments</td></tr>
<tr><td colspan="3">Response: R1. The definition of Operating Instruction allows for the discussion of general information and alternatives. The SDT points the commenter to the draft RSAW for proposed IRO-001-4 as the SDT believes it provides clarity on situations that may require the issuance of an Operating Instruction and also may alleviate concerns over the potential administrative impact. The SDT has revised the wording of the requirement to provide clarity. See summary for wording.

M2. Transmission Service Provider has been removed from M2. See summary for wording.</td></tr>
<tr><td>Hydro-Quebec TransEnergie</td><td>No</td><td>Rationale for R2 and R3 should be modified for consistency with the removal of the TSP.

R2 : Replace "compliance with the Operating Instructions" with "they" referring to the instructions. Compliance is not something that can be "physically implemented". Instructions can.

Also for consistency with M2: Remove the Transmission Service Provider from the second portion of the measure (2 occurrences)

Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).

Compliance section 1.3 : Remove all occurrences of "Transmission Service Provider". (Would have been best achieved by a "search and replace"...)</td></tr>
<tr><td colspan="3">Response: The SDT agrees and has corrected the language in the rationale box.

The SDT believes the current wording of Requirement R2 is correct as written. No change made.

Transmission Service Provider has been removed from Measure M2. See summary for wording.</td></tr>
</table>

Organization	Yes or No	Question 1 Comments
The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. Transmission Service Provider has been removed from Compliance section 1.3.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R3 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. “Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service provider, and Distribution Provider shall inform its Reliability Coordinator [within the time constraints allocated by the Reliability Coordinator in its notification protocol] of its inability to perform an Operating Instruction...”
Response: The SDT still believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes they cannot implement the instruction(s) for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT agrees that an Operating Instruction may include a timeframe given by the Reliability Coordinator, but defining a generic timeframe is not necessary, or appropriate, for a requirement. No change made.		
New York Independent System Operator (NYISO)	No	SDT should consider the use of the word ensure. We suggest revising the phase to, ‘maintain ensure the reliability...’. This term exists in other parts of this group of standards, please consider the comment for all.
Western Area Power Administration	No	Western has a concern on the use of the word ensure in R1. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the RC didn’t provide instructions that ensured the reliability of its area. We would suggest changing the last portion of the requirement to ‘...... issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.’

Organization	Yes or No	Question 1 Comments
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.		
CenterPoint Energy Houston Electric LLC	No	See comment for TOP-001-3, R1
Response: See response to TOP-001-3.		
BC Hydro	No	The new Requirement has the Reliability Coordinator issuing "Operating Instructions" rather than "Reliability Directives". The scope of "Operating Instructions" broadens to non-emergency situations. BC Hydro does not support this increase in scope.
Response: The SDT believes the use of Operating Instruction is responsive to concerns raised by FERC in the NOPR**.** The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made.		
Northeast Power Coordinating Council	No	The Purpose of IRO-004-4 is: "To establish the responsibility of Reliability Coordinators to act or direct others to act." The Functional Model states that Reliability Coordinators interact with Transmission Service Providers, and Transmission Service Providers interact with Reliability Coordinators. Why is the TSP being removed from the Applicability and the Requirements? The contents of the Rationale boxes need to be reviewed and revised. For example, The Rationale under Applicability mentions Purchasing-Selling Entity and Load-Serving Entity being deleted from IRO-001-1.1. The Rationale for Requirements R2 and R3 mentions the retirement of IRO-004-2. The Rationale for IRO-001-4 should deal with IRO-001-4. The Drafting Team should consider the removal of the Rationale Box for R2 and R3.

Organization	Yes or No	Question 1 Comments
		Suggest that the Drafting Team consider replacing the word "ensure" where used in the Requirements and Measures and VSL Table with the word "maintain". Because Transmission Service Provider is being removed from the Applicability of the standard, Transmission Service Provider needs to be removed from the body of the standard. For example, the Quality Review did not catch its use in the Data Retention section.
Hydro One	Yes	Agree with same comments as NPCC-RSC
Response: Transmission Service Providers are not listed in the Functional Model for corrective actions issued by the Reliability Coordinator, therefore they would not receive an Operating Instruction from a Reliability Coordinator. These rationale boxes are meant to provide clarity for deletions/retirements made by the SDT. However, based on comments from others, the SDT has corrected the language in the rationale box for Requirements R2 and R3. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. Transmission Service Provider has been removed from Measure M2 and the Compliance section. See summary for wording.		
Colorado Springs Utilities	No	We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following were the comments that we had in addition to SPP's comments. CSU references our previous comments again as we do not feel they were addressed correctly. 1. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 2. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. The response by the SDT referenced other requirements that require notification in other standards stating that the time requirements are covered under those requirements. The requirements referenced by the SDT do require notification at the time of an actual SOL or IROL etc. IRO-001-4 is the pre-contingency analysis that needs to be communicated. We do not feel that the

Organization	Yes or No	Question 1 Comments
		requirements referenced by the SDT cover the pre-contingency analysis required to be communicated by IRO-001-4.
Response: The SDT believes the reference should be for proposed TOP-001-3 and points the commenter to question 7.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	See VSL comments in response to question #11 below.
Response: See response to q11.		
FRCC Operating Committee (Member Services) City of Tallahassee, TAL	Yes	The groups represented by the FRCC Operating Committee support IRO-001-4 revisions in principle, however we seek clarification on the potential interpretations of the term “Operating Instructions” and the potential administrative impact to normal and emergency BES operations needed to demonstrate compliance as stipulated in the Measures.
Response: The SDT points the commenter to the draft RSAW for proposed IRO-001-4 as the SDT believes it provides clarity on situations that may require the issuance of an Operating Instruction and also may alleviate concerns over the potential administrative impact.		
Tri-State Generation and Transmission Association, Inc.	Yes	There are still mentions of the "Transmission Service Provider" even though it has been removed as an applicable entity. It is mentioned twice in Measure M2 and once again under the compliance section "1.3 Data Retention." All references to the Transmission Service Provider should be removed.

Organization	Yes or No	Question 1 Comments
Response: Transmission Service Provider has been removed from Measure M2 and the Compliance section. See summary for wording.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
NERC Compliance Policy	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comments
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Tennessee Valley Authority	Yes	
Ameren	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
MidAmerican Energy Company	Yes	

Organization	Yes or No	Question 1 Comments
Response: Thank you for your support.		

2. **Do you agree with the changes made to respond to industry comments to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes**.

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Organization	Yes or No	Question 2 Comments
ACES Standards Collaborators	No	(1) We appreciate the drafting team's consideration of previous comments and subsequent revisions. (2) We recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirements. (3) Requirement R3 is problematic as written because it implies that sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100

Organization	Yes or No	Question 2 Comments
		kV facilities are needed for reliability they would be part of the BES exception process and would be covered by the NERC defined term “Facilities.” The FERC NOPR that proposed to remand the TOP/IRO standards was issued on November 21, 2013, which was prior to the BES definition coming into effect on July 1, 2014. This is a significant justification to remove the sub-100 kV language. (4) We recommend verifying that the redlined and clean copies of the draft standard have consistent numbering of the requirements. When R1 was deleted in the redlined version, the other requirements did not reflect this change. Considering there are over 30 documents to review with this posting, it can be confusing when the requirements do not match.
Response: (1). Thank you for your support. (2). Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term and approved by FERC then a project will be undertaken to make the necessary corrections throughout these standards. No change made. (3) Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-001-3, TOP-003-3, and IRO-010-2. See summary for wording. (4) The SDT is making every effort to align the requirement numbering.		
Electric Reliability Council of Texas, Inc.	No	1. ERCOT respectfully submits that Requirement R1 is duplicative to COM-001, R1 and recommends that it remain deleted. 2. ERCOT respectfully suggests that Requirement R2 requires clarification regarding the entities with which a Reliability Coordinator shall have data exchange capabilities and what shall constitute such data exchange capabilities as some information sharing does not lend itself to data links. The following revisions are proposed: R2. Each Reliability Coordinator shall exchange data with Balancing Authorities,

Organization	Yes or No	Question 2 Comments
		Transmission Operators, and other entities as identified in the data specification developed and maintained in accordance with IRO-010 and necessary to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. [Violation Risk Factor: High] 3. ERCOT respectfully suggests that Requirement R3 may be confusing and redundant as written and proposes a streamlined, less ambiguous version for the SDT's consideration. The following revisions are proposed: R3. Each Reliability Coordinator shall monitor the Facilities, status of Special Protection Systems, and sub-100 kV facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas that are necessary to identify System Operating Limit exceedances and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Response: 1. Requirement R1 will remain deleted. 2. The SDT feels this requirement is clear as to entities the Reliability Coordinator deems it needs data exchange capabilities with and what purpose those data exchange capabilities would serve. No change made. 3. The SDT does not believe that the suggested change adds clarity. However, due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.		
Associated Electric Cooperative, Inc. - JRO00088	No	R2: The OC Review Group suggests adding the word 'its' between 'with' and 'Balancing Authorities' to provide clarity. Suggested Wording: "R2: Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments."
Response: The SDT agrees and has made this non-substantive change. See summary for wording.		

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<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comments</th></tr>
<tr><td>Hydro-Quebec TransEnergie</td><td>No</td><td>Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).</td></tr>
<tr><td colspan="3">Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made.</td></tr>
<tr><td>Dominion Compliance Policy</td><td>No</td><td>Dominion does not agree with R3, of the “clean version,” as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We would prefer to modify the requirement to read “Each Reliability Coordinator shall monitor BES Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.” It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. While Dominion acknowledges the SDT’s consideration of its comments relative to inclusion of the phrase ‘sub-100 kV facilities’ it still disagrees with the SDT’s decision to retain it in this requirement for the reasons previously stated.

M1 as written, “...and real-time Assessments.” the word “Real” needs to be capitalized.</td></tr>
<tr><td colspan="3">Response: Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.</td></tr>
</table>

Organization	Yes or No	Question 2 Comments
The measure has been corrected.		
SPP Standards Review Group Colorado Springs Utilities	No	M1 - Capitalize Real-time in the last line of Measure M1.
Kansas City Power & Light	No	M1 - Capitalize Real-time in the last line of Measure M1.
Response: The measure has been corrected.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU's etc.) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be

Organization	Yes or No	Question 2 Comments
		performed in the space of 30 minutes and may not keep pace with changing real-time conditions. The language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the "authority to approve" doesn't literally mean the same thing as "work shall not be performed without RC approval." The latter appears to be what the SDT intends, but the language does not appear to support it.
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. It is the SDT's intent that the System Operator has the authority to approve, deny, or cancel any outage affecting their ability to communicate, monitor, and analyze the system. No change made.		
Duke Energy	No	R1: Duke Energy suggests the following revision: "Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." We believe adding "its BA and TOP" narrows the scope of data sharing required by the RC. We believe the intent should be to ensure the RC has data sharing capabilities with the BAs and TOPs in its RC area and with other entities that the RC believes are needed for performing Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. R2: No comment

Organization	Yes or No	Question 2 Comments
		R3: Duke Energy suggests the following rewording: ”Each Reliability Coordinator shall monitor identified Facilities, status of Special Protection Systems, and sub-100 kV facilities necessary to identify any System Operating Limit exceedances, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Are a." We believe this rewording provides more clarity on the intent of this requirement. R4: Duke Energy suggest the following language: ”Each Reliability Coordinator shall have Energy Management Systems and SCADA data that provides information utilized by the Reliability Coordinator’s System Operator over a redundant infrastructure.” We feel the language “as written” is too broad. We feel this revision helps remove the perceived vagueness when referring to “monitoring systems”. Also, in regards to “redundant infrastructure”, we ask the SDT the following question: If an entity has redundant capability of its EMS system and one leg of that system is rendered unavailable during a planned or unplanned outage, is the RC non-compliant? In this example, the RC will not be on a redundant system due to the outage. We have concerns that the language as written in the standard would render the RC non-compliant.

Response: R1. The SDT agrees and has made this non-substantive change. See summary for wording.

R3. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.

R4. It is not the SDT’s intent to require entities to have specific tools or systems or to dictate which software tools or systems an entity has to have to perform the function described in the requirement. No change made.

Organization	Yes or No	Question 2 Comments
The purpose of redundancy is to protect against a single point of failure. Specific questions on compliance need to be submitted to NERC Compliance.		
NV Energy	No	The changes made to R2 and R5 are responsive to our prior concerns. However, the language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the “authority to approve” doesn’t literally mean the same thing as “work shall not be performed without RC approval.” The latter appears to be what the SDT intends, but the language does not appear to support it.
Response: It is the SDT’s intent that the System Operator has the authority to approve, deny, or cancel any outage affecting their ability to communicate, monitor, and analyze the system. No change made.		
Northeast Power Coordinating Council Hydro One New York Independent System Operator (NYISO)	No	The contents of the Rationale boxes must be reviewed with respect to their applicability to IRO-002-4. The Drafting Team should clarify and coordinate the requirements between voice and data equipment requirements and the associated COM-001 and IRO-002-4. The SDT should clarify the COM-001 is restricted to voice communications and the IRO-002-4 R1 is intended to address data. It is also not clear that IRO-002-4 R2 is limited to voice communication and/or data. A wording change for R2 to be considered: Each Reliability coordinator shall have the authority to approve planned outages and maintenance of its telecommunication and data exchange capabilities (as referenced in R1). Requirement R3 has had the word “telecommunication” added to it. Should also add the word telemetering to make the requirement read “...telecommunication and telemetering...”. Then use of telecommunication and telemetering should be made consistent throughout the document. In Requirement R4 delete the comma between “...Special Protection Systems, and sub-100kV...” to make it read “...Special Protection Systems and sub-100kV...”. This

Organization	Yes or No	Question 2 Comments
		makes it clear that both Special Protection Systems and sub-100kV facilities shall be monitored.
Response: The SDT agrees and has corrected the language in the rationale box. The SDT does not believe that the suggested change adds clarity. No change made. The SDT believes that the commenter is referring to Requirement R2. The wording in Requirement R2 is consistent with the wording in proposed TOP-001-3 Requirement R16. No change made. The SDT does not believe that the suggested change adds clarity. No change made.		
FRCC Operating Committee (Member Services) City of Tallahassee	Yes	However, R5 requires "synchronized information systems". The FRCC Operating Committee seeks clarification from the drafting team on what constitutes a "synchronized information system". Consider replacing the word "synchronized" with "coordinated."
Response: The SDT believes that the commenter is referring to Requirement R4. The SDT believes that a 'synchronized' information system is adequately characterized by the dictionary definition of "cause to occur or operate at the same time or rate". The SDT sees no additional clarity being provided by the suggested change. No change made.		
MRO NERC Standards Review Forum	Yes	Please see question 7.
Response: Please see response to q7.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	Yes	R4 begins with 'Each Reliability Coordinator shall monitor Facilities...' Southern suggest that the words, "Bulk Electric System" be added to R4 so that it reads 'Each Reliability Coordinator shall monitor "Bulk Electric System Facilities", consistent with the verbiage in IRO-003-2 Requirement 1. Measure 4 should also be changed accordingly. R4 - Southern suggest that utilization of the words, "as necessary" makes the requirement confusing and proposes the below verbiage to add clarity: 'Each

Organization	Yes or No	Question 2 Comments
Generation and Energy Marketing		Reliability Coordinator shall monitor "Bulk Electric System Facilities", the status of Special Protection Systems, and sub-100 kV facilities identified by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, "as being necessary to determine" any System Operating Limit (SOL) exceedances within its Reliability Coordinator Area.' Changes would apply to Measure 4 as well.
Response: R4. The use of the defined term 'Facilities' means that it is BES and the suggested change would thus be redundant. No change made. The SDT feels the language as written communicates the correct intent. No change made.		
Texas Reliability Entity	Yes	Requirement R4: Texas Reliability Entity, Inc. (Texas RE) requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality.
Response: Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.		
Florida Municipal Power Agency	Yes	The previous suggestion from the FRCC Operating committee was not taken regarding the "to approve" language in R3. As drafted this does not cover the full spectrum of authority needed by the RC. FMPA suggests replacing the words "to

Organization	Yes or No	Question 2 Comments
		approve" with "over" to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators.
Response: The SDT believes the Requirement language captures the SDT's intent of full authority to approve, deny, cancel, etc., planned outages. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	

Organization	Yes or No	Question 2 Comments
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

3. **Do you agree with the changes made to respond to industry comments to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes to the requirements based on industry comments:

Rationale Box for Requirements R2 and R3: Requirements added ~~I~~in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.)

R3. Each Reliability Coordinator shall notify impacted entities identified in its ~~the~~ Operating Plan(s) cited in Requirement R2 as to their role in ~~those~~ such plan(s).

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~ Wide Area.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 has been prevented or mitigated.

Organization	Yes or No	Question 3 Comments
Texas Reliability Entity	No	1) Requirement R1: The SDT changed “or” to “and” within the phrase “System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLS)” based on a comment. Neither the commenter nor the SDT provided justification for the change. Texas RE does not agree with the change because if either SOLs OR IROLs are exceeded then the assessment should be performed; not just if both are exceeded. Texas RE requests that the change be rejected and the original language be reinstated or explanation of why the change is correct. 2) Section 1.3. Data Retention: Texas RE does not agree with the change of data retention for R1, R2, R3, R5 and R6 from a rolling six months to a rolling 90 calendar days. The six-month requirement was aligned with the Data Retention and Sampling Team (DRAST) white paper, which indicates a six-month rolling period for high volume

Organization	Yes or No	Question 3 Comments
		data, and 90-days for voice and audio recordings. The same comment applies for R4, which was changed from 90 days to a rolling 30 days.
Response: 1) The SDT believes that the proper term here is 'and'. Using 'or' leaves the requirement open to an interpretation where either SOLs or IROLs would need to be assessed. Both need to be assessed therefore justifying the use of 'and'. No change made. 2) The SDT believes that the requirements associated with an Operating Plan for next-day operations qualifies as a high volume task and could create a documentation burden on the part of the Reliability Coordinator. To reduce this compliance burden the data retention period was reduced. A similar argument applies to Requirement R4. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. ERCOT respectfully submits that Requirement R3 is ambiguous as written. More specifically, the use of terms such as "coordinated" and "considered" are undefined and unnecessarily complicate Reliability Coordinator's responsibilities and documentation. In R2-R3, the current definition of Operating Plan states "a document". While this context is appropriate for processes/procedures determined well in advance of real time (e.g. EOP 005, EOP 008). The timeframe described is really next day and while most "Operating Plans" are documented, all plans to operate reliably may not be documented or in "a document". The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having "a document" rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single "document" and have several required elements. This can be overly prescriptive and burdensome. 2. ERCOT respectfully submits that Requirement R4 is ambiguous as written. More specifically, it is unclear as to whether the Reliability Coordinator is responsible for notification of those entities impacted in its Operating Plan or all Operating Plans referenced in Requirement R3. 3. ERCOT suggests that the SDT review the language of Requirement R5 and its VSL for consistency. In particular, Requirement R5 was modified to require that the Reliability

Organization	Yes or No	Question 3 Comments
		Coordinator ensure that a Real-Time Assessment is performed every 30 minutes. However, the VSL still assesses the condition that the Reliability Coordinator did not “perform” as opposed to did not “ensure that” the Real-time Assessment was performed. These should be reviewed and revised to ensure consistency between the requirement and its VSL. 4. ERCOT respectfully notes that Requirement R5 and the associated VSLs do not acknowledge the necessary tool outages that occur as part of planned system maintenance to ensure that Reliability Coordinator tools continue to run with high availability and accuracy. With the continuing obligations of Registered Entities to ensure the cybersecurity of their tools and the clear acknowledgment of the need for planned outages of Reliability Coordinator tools in IRO-002-4, R3, the current Requirement R5 and the associated VSLs create conflict and inconsistency amongst the overall set of Reliability Standards. If Registered Entities (and Reliability Coordinators in particular) are required to maintain their analysis tools, which maintenance may require outages of such tools, Requirement R5 should not provide that Reliability Coordinators will be penalized for the very activities they are required to conduct under its obligations set forth within the overall set of enforceable Reliability Standards. More clearly stated, it should not be a violation if an entity has a planned tool outage that causes a reasonable time deviation from the normal 30 minute timeframe. The following revisions are proposed are proposed to address this inconsistency: R5. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes except where performance is delayed as a result of a planned or unplanned tool outage and potential effects of the delay are mitigated where possible. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations] It is further recommended that the associated VSLs also be modified accordingly. 5. ERCOT has identified a potential typographical error in R6 and all of its VSLs. Specifically, the reference to “as identified in identified in Requirement R6” should likely be reviewed and revised to “as identified in Requirement R5”.

Organization	Yes or No	Question 3 Comments
		6. ERCOT respectfully reiterates its previous comment on the inconsistent language used between Requirements R5 and R6 and the LOWER VSL for Requirement R8. In particular, the word "Emergency" is used in the VSL for Requirement R8 but the condition is not specified elsewhere in the standard or the appropriate referenced requirements. Please revise the lower VSL for Requirement R8 to ensure consistency. The following language is proposed: "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated". 7. The reference in Requirements R6 and R8 to "as indicated in its Operating Plan" is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly and can cause a "plan" to vary and the impacted entities to vary. The phrase "as indicated in its Operating Plan" should be deleted. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of "Operating Plan" and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.

Response: 1. The SDT believes the commenter is referring to the new Requirement R2 (old Requirement R3). A Reliability Coordinator develops its Operating Plan by reviewing the results of its Operational Planning Analysis while taking into consideration the Operating Plans of the Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. The outcome is a coordinated plan for next-day operations. No change made.

2. The SDT believes the commenter is referring to the new Requirement R3 (old Requirement R4). The SDT concurs with your concern and has modified Requirement R3 as found in the Summary Comments above.

3. VSL responses are handled in q11.

4. IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on

Organization	Yes or No	Question 3 Comments
to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. 5. The SDT agrees and has corrected the typo. See summary for corrected requirement. VSL responses are handled in q11. 6. VSL responses are handled in q11. 7. The phrase was inserted to require the Reliability Coordinator to only notify those other Reliability Coordinators that are impacted by the Reliability Coordinator's Operating Plan. Otherwise, the Reliability Coordinator would have to notify all other Reliability Coordinators since they would all be impacted, some more than others. No change made. 8. The additional explanation under Associated Documents was provided to further enhance and clarify the definition. The SDT felt that this was a more effective and efficient way to provide this rather than incorporating it into the definition and creating a voluminous definition. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	1.3 Data Retention - Hyphenate 30- and 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Response: The SDT agrees and has made the indicated corrections.		
IRC Standards Review Committee Independent Electricity System Operator	No	a. R6 and all of its VSL: The reference to "as identified in identified in Requirement R6" should be revised to "as identified in identified in Requirement R5". b. We wish to reiterate our previous comment on the inconsistent language used between Requirement R6 (was R8 but misquoted in our previous comment as R6) and the LOWER VSL for R6 in which the word "Emergency" is used but the condition is not specified in R6.R6 stipulates that: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

Organization	Yes or No	Question 3 Comments
		However, the LOWER VSL for R6 indicates that: The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan “when the Emergency identified in Requirement R6 was prevented or mitigated.” Please revise VSL to read “when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated” as opposed to “Emergency” for consistency. c. The language between R4 and its VSL is inconsistent.R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC to “perform” to “ensure that” a Real-time Assessment is performed. However, the VSL still assesses the condition that the RC did not “perform” as opposed to did not “ensure that” the Real-time Assessment was performed. Please revise as appropriate.
Response: The SDT agrees and has corrected the typo. See summary for corrected requirement. VSL responses are handled in q11. b. and c. VSL responses are handled in Question 11.		
Northeast Power Coordinating Council Hydro One	No	“Ensure” or “ensured” should not be used in the standard. The contents of the Rationale boxes must be reviewed to ensure they are consistent with their associated Requirements. For example, the Rationale for Requirements R5 and R6 refers to the use of the word “impacted”. Impacted is not used in Requirement R5. The contents of the Rationale for R1, and R3 and R4 should be expanded to provide a short background statement for the Rationale. The wording of requirements should be made consistent. Why is Requirement R7 being deleted?
Response: The SDT has reviewed the use of ‘ensure’ throughout the standard and believes that the use of the term in this standard is correct. No change made.		

Organization	Yes or No	Question 3 Comments
Please refer to the clean version of the standard. The new Requirements R5 and R6 contain 'impacted'. Granted, the requirement numbers in the redline version did not align with the references in the Rationale Boxes which has now been corrected. . SOLs were included in Requirement R1 as a result of a concern expressed by FERC in paragraph 96 of the NOPR. Likewise, Requirements R2 and R3 were added to address concerns expressed in the SW Outage Report and by the Independent Expert Review Panel. Additional wording has been included in the Rationale Box for Requirements R2 and R3. The SDT decided to delete Requirement R7 because it is redundant with the more generic proposed IRO-001-4, Requirement R1.		
Associated Electric Cooperative, Inc. - JRO00088 South Carolina Electric and Gas	No	In R5, suggest expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In R8, the OC Review Group suggests removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs. Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated."
Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the		

Organization	Yes or No	Question 3 Comments
Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Georgia Transmission Corporation	No	In R5, suggest expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In R8, suggest removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs. Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated."
Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Consumers Energy Company	No	I have a concern with the evidence for compliance with Requirement 4. The Standard as written does not clearly define parties who must be notified. The reference to the Operations Plan does not require the inclusion of any non-registered entity.

Organization	Yes or No	Question 3 Comments
Response: New Requirement R3 (old Requirement R4) indicates that the Reliability Coordinator must notify those entities that it determined were impacted in its Operating Plan which is based on its Operational Planning Analysis as conducted in Requirement R1. The SDT has made clarifying changes to Requirement R3 which should alleviate your concern. See the Summary Consideration.		
Dominion Compliance Policy	No	In R8, Dominion suggests removing the words ‘prevented or’ because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs.
Response: Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a ‘stand down’ notification such that those processes are returned to normal. No change made.		
Florida Municipal Power Agency	No	It seems the SDT did not understand FMPA’s previous comment regarding R1. FMPA’s comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase “N-1 Contingency planning” no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the RC’s OPA supposed to consider N-2 events? N-3? Loss of an entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs and IROLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase “in accordance with its SOL Methodology”. Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards. The number of contingencies to be studied is also absent from the definition of Real-time Assessment.

Organization	Yes or No	Question 3 Comments
Response: The SDT does not want to be overly prescriptive. The Transmission Operator has the obligation to preserve the reliability of the interconnected Transmission system. The Contingencies to be handled in an Operational Planning Analysis are laid out in the Reliability Coordinator's SOL methodology and the SDT expects that an entity will adhere to that methodology when performing its Operational Planning Analysis. No change made.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU's etc.) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions.

Organization	Yes or No	Question 3 Comments
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made.		
Duke Energy	No	R1: No Comment R2: No Comment R3: No Comment R4: No Comment R5: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an RC's Energy Management System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R6: We believe the incorrect requirement was referenced in R6. The phrase should be as follows :"when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated." Please change the reference of "R6" with "R5" as seen in the example above. R8: Duke Energy suggests the following revision: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated." We suggest removing "prevented" because the prevention of SOL/IROL

Organization	Yes or No	Question 3 Comments
		exceedances will be difficult to prove and would not typically be communicated to BAs and TOPs. The communication activities should be restricted to communications of activities to mitigate a potential SOL/IROL exceedance and not the prevention.

Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.

Requirement R6 (new Requirement R5) – The SDT agrees and has corrected the typo. See the Summary Consideration for the corrected requirement. VSL responses are handled in Question 11.

Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.

Organization	Yes or No	Question 3 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R4 - It is not clear why the SDT removed the qualifier "NERC registered". Southern recommends adding "NERC registered" back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. In addition, Southern noted that the SDT responded with the following comment in consideration of comments received for R4."Impacted goes beyond the concept of those entities that have an active role to play in the Operating Plan. It also includes those entities which may not have an active role to play in the plan but are still impacted by the given operating condition. For example, an entity may have Load impacted by a given situation and the only available option that entity may have is to shed that Load. But if the plan doesn't call for that entity to shed the Load, then the entity doesn't have an active role in the plan but is still impacted by the situation and therefore is deserving of notification." It is

Organization	Yes or No	Question 3 Comments
		very unclear on what expectation the SDT is suggesting in this comment. If the RC conducts a next day study and identifies potential issues, the RC will develop a plan to resolve the issue. This plan will be communicated to the NERC registered entity that is responsible for implementing the plan. The example provided by the SDT is unclear and confusing in that it introduces an entity that was never part of the plan to resolve the issue. If this entity was never part of the plan, why would or should the RC notify such entity? R8 - Southern suggests modifying R8 as follows (include "actual") to require notification in the event of an actual SOL or IROL exceedance within the RC area, but not require notification in the case where there was a possible SOL/IROL exceedance, but system conditions changed that cause the potential issue to subside. Southern believes that requiring notification for the latter is a good utility practice, but does not maintain or enhance reliability as it is nothing more than a notification that "nothing is required any longer for what could have been "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. [Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations] Southern also recommends moving the word "known" in the definition of Operational Planning Analysis to the beginning of the second sentence to reflect that the evaluation shall reflect applicable "known" inputs. The "known" should apply to each of the inputs and not just Protection Systems and SPS status and degradation. The Operational Planning Analysis should reflect what the TOP knows at the time the evaluation is conducted. TOPs continue to update the studies as updated or "known" information becomes available. See suggested revision below. Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable known inputs including, but not limited to, load

Organization	Yes or No	Question 3 Comments
		forecasts; generation output levels; Interchange; Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Response: Requirement R4 (new Requirement R3) – There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. In the referenced example, the impacted Load may only suffer the consequences of the operational condition and still not play an active role in the mitigation of that condition. If for example, the Load is suffering from low voltage and its Distribution Provider has done everything it can do to alleviate the situation short of shedding Load, the plan could call on other entities identified in the plan to take action to assist in relieving the under-voltage situation such that Load would not have to be shed. Since its Load is on the line, the Distribution Provider should be notified of the potential for the condition and then notified when that threat is mitigated. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates a real or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made. Operational Planning Analysis – The SDT believes that the definition is worded correctly as stated since it now includes the word 'applicable'. No change made.		
Hydro-Quebec TransEnergie	No	R6: Replace "Reliability Coordinator Wide Area" by "Wide Area" for consistency with modifications made to R1. Compliance section 1.2: What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer

Organization	Yes or No	Question 3 Comments
		to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R4, R6 and R8 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3. Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: Requirement R6 (new Requirement R5) –The SDT agrees and has made the suggested change. See the Summary Consideration. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. VSL responses are handled in Question 11. Associated Documents – It is the normal practice to include this type of clarifying information, including the content of the Rationale Boxes, in this section of the standard. It provides a quick reference, in the standard itself, for further clarification of the requirements. No change made.		
PacifiCorp	No	The implications of removing the term NERC Registered from R4 are unclear because a Planning Coordinator may not be able to rely on information provided by unregistered entities. If the RC in IRO-008-2 M3 creates an Operating plan that includes non-registered Entities (TOP-002-4 R4 clearly shows that NERC thinks that non-registered entities WILL be included in some Operating Plans), the TOP responsibility of TOP-002-4 will only pertain to the NERC registered entities. This creates a serious potential reliability "gap" that must be addressed before this draft can be evaluated.
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those		

Organization	Yes or No	Question 3 Comments
unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
New York Independent System Operator (NYISO)	No	The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes may have been based on the requirements to be within IROL's in 30 minutes. The 30 minute assessment for SOL's may be over prescriptive as some SOL could be up to 4 hours.
Response: The SDT does not agree that this requirement should be limited to IROL evaluations. The FERC NOPR made it clear that Transmission Operators should be performing SOL evaluations as well. The SDT wants to reinforce that a Real-time Assessment does not imply that all identified SOL exceedances need to be resolved within 30 minutes. SOL exceedances need to be mitigated consistent with the Transmission Operator's Operating Plan as highlighted in the SOL Exceedance White Paper. IROL exceedances would need to be mitigated consistent with the IROL T_v. No change made.		
Peak Reliability	Yes	R1 as written requires the RC to perform an OPA to assess whether planned operations will exceed SOLs and IROLs in its Wide Area. NERC defines Wide Area as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits". According to this NERC definition, the Wide Area does not include actual Facilities outside the RC Area, but rather includes flow and status information from adjacent RC Areas for the purposes of IROL calculation (whether the IROL is in the RC Area, in the adjacent RC Area, or spanning across multiple RC Areas). It brings in information from outside the RC Area for IROL calculation - it does not bring in additional Facilities outside the RC Area for general monitoring. Therefore, requiring an OPA to assess SOL and IROL exceedances in a Wide Area actually doesn't make sense, given the fact that the Wide Area does not include actual Facilities outside the RC Area, but rather information from outside the RC Area. Given the NERC definition of Wide Area, the requirement can only make sense if it requires the OPA to assess whether planned operations in its Wide Area (i.e., flows and statuses outside its RC Area for the purposes of IROL calculation) is expected to exceed any of its SOLs and IROLs. Peak

Organization	Yes or No	Question 3 Comments
		believes that the standard should be rephrased to state, “Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations within its Wide Area for the next-day will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).” With this language change, the flow and status information from the Wide Area are included in the RC’s OPA to determine SOL and IROL exceedances appropriately (including IROLs within the RC Area as well as IROLs that span multiple RC Areas).This language change will also bring consistency with its companion requirement TOP-002-4 R1, which states, “Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).” Peak believes this language change accurately reflects the NERC definition of Wide Area and ensures SOLs and IROLs are addressed appropriately to ensure reliability across the board. R5: It should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.
Response: Requirement R1 – The wording change being proposed limits the Reliability Coordinator’s assessment to the SOLs and IROLs only within its Reliability Coordinator Area. This then limits the overall benefit of the Wide Area. If conditions within Reliability Coordinator A’s Reliability Coordinator Area create the potential for SOL or IROL exceedances outside its Reliability Coordinator Area, but still within its Wide Area, but those conditions are not within the Wide Area view of neighboring Reliability Coordinator B’s Wide Area view, then without notification by Reliability Coordinator A, Reliability Coordinator B would not be aware of the situation. Additionally, the SDT believes that the definition of Wide Area does include knowledge of Facilities within that Wide Area. If not, why would status information be included? A Reliability Coordinator must have those Facilities included in its models in order to factor in the status of those Facilities. Given the gap presented by the proposed language and the belief that Facilities are already properly accounted for; the SDT prefers the original language. No change made. Requirement R5 (new Requirement R4) – The same evidence would be required regardless of which party actually conducts the assessment. Even though a Reliability Coordinator may delegate that task to a third party, the Reliability Coordinator is still		

Organization	Yes or No	Question 3 Comments
accountable from a compliance standpoint. In the situation where a third-party actually performs the assessment, the only additional evidence that may be required is the delegation agreement between the Reliability Coordinator and the third party. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
American Transmission Company, LLC	Yes	Although proposed IRO-008-2 is not applicable to ATC, changes were made by the SDT to Requirement R1 and the proposed term “Reliability Coordinator Wide Area” that addressed ATC’s comments in response to the SDT’s 1st posting.
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comments
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

4. **Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1, Part 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Organization	Yes or No	Question 4 Comments
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated.
Ingleside Cogeneration , LP	No	ICLP agrees there are times where the RC will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of RCs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned RC - that a full evaluation by an independent panel would take place afterwards.
BC Hydro	No	The new Requirement has the Reliability Coordinator able to ask for "sub-100 kV' data if it deems necessary. This is an increase in scope from the data the RC currently asks

Organization	Yes or No	Question 4 Comments
		for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
Response: Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
ACES Standards Collaborators Georgia Transmission Corporation	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards.
Response: As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made. Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy does not agree with the structure of R1.2. While Protection System owners generally monitor the status of their Protection Systems CenterPoint Energy is very concerned that the proposed language would require Protection

Organization	Yes or No	Question 4 Comments
CPS Energy		System owners to continuously notify their respective RC of the status of each Protection System which would be a very onerous task with questionable reliability benefit. In addition, for the RC to monitor the status of all Protection Systems in their area would be an overwhelming burden with little reliability benefit. The Company recognizes the need to notify an RC of a Protection System failure that impacts System reliability as required in PRC-001 and therefore recommends Protection Systems and Special Protection Systems be split into separate sub bullets as such: 1.2. Provisions for notification of current Protection System failures that impact System reliability. 1.3. Provisions for notification of current SPS status or degradation that impact System reliability. These comments would also apply to TOP-003-3.
Response: The SDT does not intend for the Reliability Coordinator to monitor Protection Systems rather the intent is for the equipment owner to notify the Reliability Coordinator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. The suggested change is semantic in nature. Both portions of the compound subject are modified by the descriptive prepositional phrase: "…Protection System and Special Protection System status or degradation that impacts System reliability." No change made.		
Duke Energy	No	Duke Energy does not disagree that the types of data exchanges described in this proposed IRO-010 are necessary. However, we believe that these data exchanges currently take place within the context of various existing ERO Requirements and/or various existing agreements between the Applicable Entities. Therefore we do not believe there is a need to codify these requirements in another ERO Standard. As written, this Standard simply creates additional administrative burden on the industry while providing no incremental reliability benefit. As written, Duke Energy believes this Standard would simply become a candidate for a future Paragraph 81 submittal.
Response: This proposed standard is directly responsive to the SW Outage Report Recommendation #3. No change made.		
Hydro-Quebec TransEnergie	No	R1: Replace the last sentence with "The data specification shall include but is not be limited to: Otherwise the "shall" applies to "not be limited to". That would mean that the data specification shall include other items that are not listed.

Organization	Yes or No	Question 4 Comments
		Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Compliance section 1.3 : Remove Planning Coordinator and Transmission Planner Table of Compliance Elements: VSLs for R2 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.
Response: The suggested wording change is semantic in nature and the SDT does not believe it adds clarity. No change made. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. Compliance Section 1.3 – The SDT agrees, and removed Planning Coordinator and Transmission Planner. Interchange Authority was removed in the previous posting. VSL responses are handled in q11.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term “as deemed necessary” in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of “Section 4 - Measurability” of the NERC document titled Acceptance Criteria of a Reliability Standard states “Words and phrases such as “sufficient”, “adequate”, “be ready”, “be prepared”, “consider”, etc. should not be used.” ReliabilityFirst believes the phrase “as deemed necessary” is such a phrase, which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.

Organization	Yes or No	Question 4 Comments
Response: In Requirement R1, Part 1.1, "as deemed necessary" refers to the certain data elements that the Reliability Coordinator decides is needed. This would not be a measurement component of this requirement, since Requirement R1, Part 1.1 requires the publication of a list, which can be objectively measured during an audit. No change made.		
Indiana Municipal Power Agency	No	The use of a documented specification for the data needed by the Reliability Coordinator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instances where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Reliability Coordinator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means Generator Operators in this RC area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.
Response: The ability of the Reliability Coordinator to request and receive the data necessary to preserve reliability is a foundation of coordinated system operations. The suggested change would result in an unmeasurable and non-auditable standard. No change made.		
Electric Reliability Council of Texas, Inc.	No	Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.

Organization	Yes or No	Question 4 Comments
Response: This data concerning Protection System status is currently collected routinely and data transfer mechanisms are in place. Twelve months is a reasonable time frame to implement Requirement R3. The SDT does not intend for the Reliability Coordinator to monitor Protection Systems rather the intent is for the equipment owner to notify the Reliability Coordinator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. No change made.		
Seattle City Light		SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation. For IRO-101-2, SCL asks that the implementation times be extended from nine and twelve months to eighteen and twenty-four months, because it may take longer than one year to negotiate and implement the necessary data exchange agreements among impacted entities. SCL's recommended implementation language is as follows: Section 5. Proposed Effective Date. Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Organization	Yes or No	Question 4 Comments
Response: Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
Peak Reliability	Yes	IRO-010-2 R1 states, "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." The concern with this language is the limiting nature of the scope of the data specification. The OPA is limited to data for next-day operations. R1 should not confine the RC's data specification to data for its OPA and RTA only, but rather should facilitate the RC to obtain the data it needs to perform its RC functions overall. With the current language, a TOP or BA may be able to claim that they have no compliance obligation to provide the RC with data it needs to perform its reliability functions. Peak recommends that R1 be rewritten to state: "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its reliability functions." R2 should be updated similarly.
Response: The SDT believes that the current wording allows for a Reliability Coordinator to obtain the data it needs. No change made.		
Texas Reliability Entity	Yes	Requirement R1.1: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality.
Response: The SDT has clarified its intent in revised wording. See summary for wording.		

Organization	Yes or No	Question 4 Comments
Colorado Springs Utilities	Yes	No Comments
South Carolina Electric and Gas	Yes	SCE&G is in agreement with the SERC OC comments.
Northeast Power Coordinating Council	Yes	
Hydro One	Yes	Agree with same comments made by NPCC-RSC
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 4 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comments
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	
Ameren	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
Response: Thank you for your support.		

5. **Do you agree with the changes made to respond to industry comments to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes to the standard based on industry comments:

- **M1.** Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.
- **R5.** Each Reliability Coordinator that ~~identified~~Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.
- **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that ~~identified~~identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
- **Data retention:** Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R3, R4, and R7 ~~and R9~~ and Measures M3, M4, and M7~~ and M9~~.
- **Data retention:** Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirement~~s~~ R6 ~~and R8~~ and Measure~~s~~ M6~~ and M8~~.

Organization	Yes or No	Question 5 Comments
Electric Reliability Council of Texas, Inc.	No	1. ERCOT notes that the consolidated set of IRO and TOP Reliability Standards utilize the terms “Wide Area” and “Reliability Coordinator Area”. If these phrases are expected or interpreted to be synonymous, ERCOT suggests use one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion.

Organization	Yes or No	Question 5 Comments
		2. To ensure consistency, ERCOT recommends that, in Requirement R1.6, "provisions for" is removed and the sub-requirement begins with "Periodic". 3. ERCOT respectfully recommends deletion of Requirement R3 as it is duplicative of IRO-008, Requirements R4 and R6. If the distinguishing factor and reason for inclusion is the acknowledgment of Emergency conditions, ERCOT recommends that such language is added to IRO-008. 4. ERCOT respectfully recommends deletion of Requirement R4 as it has been rendered moot by revisions to Requirement R6 and R7. Specifically, since Requirement R6 requires impacted Reliability Coordinators to implement any action plan developed by the Reliability Coordinator with the emergency and Requirement R7 requires assistance so long as the Reliability Coordinator with the emergency has implemented its emergency procedures, the dictation of operating state by other Reliability Coordinators is unnecessary. 5. ERCOT respectfully recommends deletion of Requirement R5 as it is duplicative of IRO-001-4, Requirement R1. Specifically, since Reliability Coordinators always have primary responsibility and ultimate authority to act when they observe conditions in their area that threaten reliability, disagreement with the Reliability Coordinator's assessment of the conditions by another entity is of no consequence. However, if the objective is to ensure that Reliability Coordinators assist each other in Emergencies, Requirements R5 and R7 could be eliminated and Requirement R6 could be modified as follows: R6. Each impacted Reliability Coordinator shall implement any actions and/or provide any assistance requested by the Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area unless such actions would violate safety, equipment, regulatory, or statutory requirements. 6. ERCOT respectfully notes that it is unable to discern the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. ERCOT urges the SDT and NERC to conduct a thorough and

Organization	Yes or No	Question 5 Comments
		independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays. 7. ERCOT respectfully recommends that, for consistency, the VSLs for Requirement R2 be modified to remove references to criteria and state that Reliability Coordinator failed to maintain Operating Plans, Processes, or Procedures pursuant to one part of Parts 2.1 - 2.3, two parts of Parts 2.1 - 2.3, and so on. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of “Operating Plan” and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.

Response: 1. The definition of ***Wide Area***: The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. The definition of ***Reliability Coordinator Area***: The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made.

2. The SDT believes **“**provisions” is correct for the idea being expressed. No change made.

3. Requirement R3 speaks to notification of Emergencies. Proposed IRO-008-2 Requirement R4 addresses periodicity of Real-time Assessments and Requirement R6 outlines requirements to act for notification of mitigation of SOL and IROL exceedances identified in the Operating Plan. These are not duplicative. No change made.

4. The SDT does not feel that the suggested change adds to reliability or corrects a defect in the standard and declines to make the suggested change at this time.

5. Proposed IRO-001-4 requirement R1 outlines the method by which Reliability Coordinators will act or direct others to act, i.e., issuing Operating Instructions. Proposed IRO-014-3 Requirement R5 requires development of an action plan. Said action plan may not include any Operating Instructions at all. No change made.

Organization	Yes or No	Question 5 Comments
6. Data retention for Requirements R3 and R4 has been addressed. See summary for wording. 7**.** VSL responses are handled in q11. 8. The SDT does not feel that a revised definition of Operating Plan is required. The text included under Associated Document is simply an indication of the SDT's intent as to how it anticipated that Operating Plan would be used with respect to this standard. No change made.		
Independent Electricity System Operator IRC Standards Review Committee New York Independent System Operator (NYISO)	No	a. We generally agree with the changes made to IRO-014-3. However, the replacement of "other" with "adjacent" may leave a reliability gap. For example, the notification of Transmission Loading Relief may require "notification or coordination of actions" by, and can have an impact on, RCs other than just the adjacent RCs. Since the words "may impact" already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word "other" into R1, replacing "adjacent". b. We do not have a preference, but we ask the SDT to review the use of the phrase "Wide Area" in IRO-008-2 (and other IRO standards) and the phrase "Reliability Coordinator Area" in IRO-014-3. If these phrases are expected or interpreted to be synonymous, we suggest using one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion. c. Retention Period: We are unable to find the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors.
Response: a**. "**Other" was replaced by "adjacent" due to overwhelming response by the industry during the first posting. The SDT believes that notifications concerning Transmission Loading Relief are handled through a separate and distinct mechanism. No change made.		

Organization	Yes or No	Question 5 Comments
b**.** The definition of ***Wide Area*****:** The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. The definition of ***Reliability Coordinator Area*****:** The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made. c. Data retention for Requirements R3 and R4 has been addressed. See summary for wording.		
Hydro-Quebec TransEnergie	No	Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. The SDT does not understand the comment as no white paper is included in this standard. No change made.		
Georgia Transmission Corporation South Carolina Electric and Gas	No	In R1.1, suggest adding “as identified in R1” at the end of the sentence to identify the criteria and process being addressed. Suggested Wording: “R1.1: Criteria and processes for notifications as identified in R1.” Suggests adding “may” before “impact adjacent Reliability Coordinator Areas” in M1 to match R1. Suggested Wording: “M1: Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation

Organization	Yes or No	Question 5 Comments
		shall include dated, current in force documentation with the specified elements, and notes from periodic communications.
Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made. The SDT agrees and has made the suggested change. See summary for wording.		
Dominion Compliance Policy	No	In R1.1, Dominion suggests adding “as identified in R1” at the end of the sentence to identify the criteria and process being addressed. Suggested Wording: “R1.1: Criteria and processes for notifications as identified in R1.”
Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made.		
Duke Energy	No	R1.1 - Duke Energy suggests the following language: ”Criteria and processes for notifications as identified in R1.”This provides the clarity on the specific notifications that are required with adjacent RC(s) as defined in R1. R2: No Comment R3: No Comment R4: No comment R5: Duke Energy suggests the following revision: “Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.” We believe “identifies” is the appropriate wording. R6: “Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency,

Organization	Yes or No	Question 5 Comments
		unless such actions would violate safety, equipment, regulatory, or statutory requirements." We believe "identifies" is the appropriate wording.
Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made. The SDT agrees and has made the suggested change. See summary for wording. The SDT agrees and has made the suggested change. See summary for wording.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern agrees with the compliance assessment approach and note to the auditor in the RSAW and recommends that the SDT incorporate these concepts into the standard itself. The RSAW clearly recognizes that events / Emergencies have varying levels of significance. Southern continues to think the current definition of "Emergency" is too broad and is misused in standards development. This standard, and in particular requirements to notify neighboring RCs, should be focused more on issues that can truly impact them, not any situation that could be interpreted as an "Emergency" as it is currently defined. Southern recommends the SDT replace Emergency with Adverse Reliability Impact as it was before. If the SDT does not accept this recommendation, the SDT should consider modifying the requirements or even the definition of "Emergency" to incorporate the concept that an "Emergency" is an operating condition which has not been studied or for which no mitigation plan has previously been developed. For example, having a contingency occur which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance, is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible.

Organization	Yes or No	Question 5 Comments
Response: Emergency is used as it is more inclusive which may lead to more communication. The possession of a mitigation plan does not mean an Emergency doesn't exist. In fact, the mitigation plan is in direct response to an identified Emergency. No change made.		
Northeast Power Coordinating Council Hydro One	No	The Rationale for Requirement R1 explains what review changes were made, and do not address the contents of the Requirements. The Rationale for Requirement R1 should be removed. Measure M1 reflects Part 1.5 not being removed. Why is Part 1.5 being removed? A RC should have the detailed authority. What Requirements does the Rationale on page 7 refer to? The replacement of the word "other" with "adjacent" may leave a reliability gap. Because the words "may impact" already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word "other" into R1. The Drafting Team should review the use of the phrase "Wide Area" in IRO-008-2 (and other IRO standards) and the phrase "Reliability Coordinator Area" in IRO-014-3. If these phrases are synonymous, then use of one or the other should be decided upon. Regarding the Retention Period, there are no data retention periods for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors. Suggest restoring the standard to its original wording.
Response: 1. The SDT agrees and has deleted the rationale box.		

Organization	Yes or No	Question 5 Comments
2. Requirement R1, Part 1.1.5 was deleted as the Reliability Coordinator's authority to act is implied. Measure M1 accurately reflects the requirement language. No change made. 3. Rationale on page 7 refers to Requirement R7 and why the language was added. 4. **"**Other" was replaced by "adjacent" due to overwhelming response by the industry during the first posting. The SDT believes that the wording is correct. No change made. 5. Definition of <u>*Wide Area*</u>**:** The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. Definition of <u>*Reliability Coordinator Area*</u>**:** The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made. 6. Data retention for Requirements R3 and R4 has been addressed. See summary for wording.		
Texas Reliability Entity	Yes	Requirements R1 and R2: Texas RE requests the SDT consider whether including Same-Day Operations in the Time Horizon is appropriate. The measures for R1 and R2 are focused on the maintenance of the Operating Procedures, Operating Processes and Operating Plans and not on any specific same-day actions that need to be taken. Texas RE suggests that Same-Day Operations be removed from the Time Horizon for R1 and R2. The Time Horizon of Operations Planning is correct. If the SDT disagrees with the suggested removal of the Same-Day Operations Time Horizon then we request an explanation of why it is appropriate to include it.
Response: The measures simply reflect the language in the requirements and do not apply to any specific time horizon. The SDT believes that Same-day Operations is a valid time horizon for implementing Operating Procedures, Operating Processes, or Operating Plans. No change made.		
Peak Reliability	Yes	The new R4, R5, and R6 should also include "actual or expected Emergency" like R3.

Organization	Yes or No	Question 5 Comments
Response: Since Requirements R4, R5, and R6 follow Requirement R3 in logical and sequential order, the 'actual or expected' language is automatically included by default in the requirements following Requirement R3 and addition of that language would be superfluous. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 5 Comments
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 5 Comments
PJM Interconnection	Yes	
CPS Energy	Yes	
MidAmerican Energy Company	Yes	
Response: Thank you for your support.		

6. **The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes based on industry comments:

R1 Part 1.3. Define the process to evaluate the impact of Transmission and ~~generator~~generation outages within its Wide Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning~~Long-term Planning]*

Organization	Yes or No	Question 6 Comments
City of Austin dba Austin Energy (AE)	No	AE believes R3 and R4 are redundant with requirements in TPL-001-4. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. AE notes the SDT's response in comments, "The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document." AE suggests these changes should all be considered under the TPL-001-5 SAR and not in a separate IRO-017-1 standard.
Response: The SDT disagrees, and notes that approved TPL-001-4 does not require sharing of Planning Assessments with the impacted Reliability Coordinator. The SDT continues to believe that including this requirement in proposed IRO-017-1 is necessary until a future revision of TPL-001-4. No change made.		

Organization	Yes or No	Question 6 Comments
Georgia Transmission Corporation	No	(1) GTC disagrees that outages are planned for the near term planning horizon (years 1 - 5). Outages are planned and scheduled within the operational planning horizon (up to year 1). The Planning Assessment only covers the near term and the long term planning horizons; it does not cover the operational planning horizon. Furthermore, the RC model can only include the current system that has been built and deals with real time parameters. They cannot grant outages on proposed planning solutions. The Planning Assessment does not provide any useful information for scheduling outages in the operations horizon. An outage request for construction of new stations, lines, or facility upgrades is what is required so that the RC can run a real-time assessment and grant approval for outages. R1 and R2 adequately cover the process to grant outages as they are requested, and sufficiently cover the purpose of this standard. GTC believes R3 and R4 are not necessary for outage coordination in the operations horizon and should be eliminated from this Standard. Additionally, the purpose statement should remove reference to Near-Term Transmission Planning Horizon.
Bonneville Power Administration	No	Regarding R4, Transmission Planning Assessments for the Near Term Planning Horizon do not consider outages that are less than one year in duration. If the transmission system is incapable of serving expected peak load during the Near Term Planning Horizon, current TPL standards and the future TPL-001-4 dictate Corrective Action Plans be undertaken and put in place. As currently written, R4 appears to be duplicative of TPL-001-4. BPA suggests R4 be rewritten to direct TOP and BA coordinate outages conflicts within the Operations Planning Horizon. BPA believes altering R4 in this fashion covers the reliability gap identified by the SW Outage Report, the IERP and FERC with respect to planning of outages. Additionally, this change will logically align R4 with R1.1.2, and R2, directing coordination between RC and TOP/BA.
Response: The SDT disagrees, and notes that some outages are planned over a year in advance. The SDT is intentional about including the Near-Term Transmission Planning Horizon for this reason. The SDT does recommend that proposed IRO-017-1		

Organization	Yes or No	Question 6 Comments
Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. As an overarching comment, the proposed standard references both transmission and generation outages, but then appears to focus in on transmission outages. As a result, entities responsible for generation outages do not appear to be adequately addressed relative to potential obligations to comply with Reliability Coordinator processes that are developed. This oversight could have significant consequences and the standard should be reviewed to ensure that no gaps exist. At a minimum, those entities responsible for generator outages should be included under the Applicability Section as well as other applicable Requirements (e.g., Requirement R2). More specifically, during the last posting, ERCOT commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While ERCOT agrees that such details can be elaborated in the process document, Part 1.1.2 and other requirements should be expanded to include all appropriate entities to facilitate RC development of a workable and appropriate outage coordination process involving the correct entities. 2. ERCOT is unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners

Organization	Yes or No	Question 6 Comments
		and/or operators. Corresponding changes will need to be made to Requirement R2 as discussed above. ERCOT respectfully notes that Requirement R1 requires some revisions to ensure clarity and ensure that the obligations imposed are clear and unambiguous. Specifically, the requirement indicates that Reliability Coordinators shall develop, implement, and maintain and outage coordination process. However, it does not define what maintenance shall be performed. R1. Each Reliability Coordinator shall develop and implement an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] ERCOT believes “develop” in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 “document and” with “maintain”, which is sufficient. Document is purely administrative. M1 infers a requirement by including “dated”. By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. Additionally, it is noted that use of the term “define” may not adequately connote the level of detail expected regarding the documentation of the outage evaluation and coordination process referenced in sub-requirements R1.3 and R1.4. Accordingly, the following revisions are suggested: 3. ERCOT respectfully notes that Requirement R2 requires some revisions to ensure clarity and ensure that the obligations imposed upon participants in each Reliability Coordinator’s outage coordination process are clear and unambiguous. Accordingly, it is recommended that Requirement R2 be modified as follows: R2. Each Transmission Operator and Balancing Authority shall perform the roles, responsibilities, and activities assigned to its function in its Reliability Coordinator

Organization	Yes or No	Question 6 Comments
		outage coordination process. [Violation Risk Factor: Low Medium] [Time Horizon: Operations Planning] 4. ERCOT respectfully notes that TPL-001-4 already requires distribution of Planning Assessments to various entities. To ensure that all obligations related to Planning Assessments are clearly communicated and consolidated such that they are easily identified and fulfilled, it is recommended that Requirement R3 be deleted from IRO-017 and Requirement R8 within TPL-001-4 be reviewed for the necessary revisions.
Response: The SDT disagrees that Transmission outages are emphasized more than generation outages, and notes that the intention of this standard is to cover both. 1 & 2 - Since the requirement is for the outage coordination process document, the SDT does not consider it necessary to include an exhaustive list of entities, especially in the applicable entities section. Some of the comments appear to be based on the first draft posting of this standard which was subsequently changed. No change made. 3 – The SDT disagrees that a change to this language is necessary. No change made. 4 – The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Northeast Power Coordinating Council Hydro One	No	“Operations Planning” in the Purpose is not defined in the NERC glossary and should not be capitalized. Regarding the Rationale and Time Horizon boxes on page 5: The words in the Rationale is appropriate for a guideline or announcement. It does not belong in a Rationale box.

Organization	Yes or No	Question 6 Comments
		Neither "Time Horizon" nor "Operations Planning Time Horizon" is in the NERC Glossary and should not be capitalized. If those terms are to be considered for inclusion in the NERC Glossary, then they should be included on the Definitions of Terms Used in Standard. The R1 wording "...within its Reliability Coordinator Area" should be removed. Part 1.4 refers to "...other Reliability Coordinators". The box "Note on part 1.5" does not belong in the standard. It is a comment response. "Near-Term Transmission Planning Horizon" is defined as "The transmission planning period that covers Year One through five." The Rationale for Requirement R4 should be revised to just address the "why", and justification for R4. During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, sub-Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support sub-Part 1.1.2 as written, and suggest the Drafting Team to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.

Response: The SDT notes that the rationale boxes will be removed after approval and are purely for explanatory purpose during the standard drafting process. No change made.

Organization	Yes or No	Question 6 Comments
While Time Horizon and Operations Planning Time Horizon are not defined terms in the NERC Glossary, the terms are used in standards in the Time Horizon section that follows every requirement. The rationale box where these terms appear will be removed after final balloting. No change made. R1 – The SDT disagrees and believes that the current language clarifies that the Reliability Coordinator's authority is limited to its Reliability Coordinator Area. However, coordination with neighboring Reliability Coordinators is important, as noted in Requirement R1 Part1.4. No change made. R1.1.2 and R2 – The SDT continues to believe that additional details can be provided in the outage coordination process document. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	In R4, the OC Review Group suggests adding "on the BES" before "with planned outages" to clearly define the BES as the subject portion of the system. Suggested Wording: "R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon."
Response: The SDT believes that this change is unnecessary as standards are written for the BES unless stated otherwise. No change made.		
American Transmission Company, LLC	No	ATC requests the SDT to consider making the following modifications to the proposed Requirements R3 and R4: R3 - To be consistent with the "Long-term Planning" Time Horizon in Requirement R4 and due to Requirement R3's association with the long-term horizon Planning Assessments, ATC suggests that the Time Horizon for Requirement R3 be changed to "Long-term Planning." R4 - To be more consistent with paragraph 90 of the FERC NOPR and because the term "planned outages" has no specific NERC or industry-wide meaning, ATC suggests that the wording of "planned outages" in Requirement R4 be replaced with

Organization	Yes or No	Question 6 Comments
		"scheduled generation, transmission maintenance and transmission construction outages."
Response: R3 – The SDT agrees and has corrected the time horizon. R4 – The SDT believes that the term "planned outages" is sufficiently explanatory. No change made.		
IRC Standards Review Committee Independent Electricity System Operator	No	During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
Response: The SDT continues to believe that additional details can be provided in the outage coordination process document. No change made.		
Clark Public Utilities	No	I plan to vote affirmative but wanted to provide a suggestion. R3 is a requirement for the PC and TP to provide its Planning Assessment to the RC. I agree that this should be done, however, it is out of place in IRO-017. It should instead be included in the TPL-001 standard. Even if R3 is retained I encourage a process to eventually move it from IRO-017 to TPL-001.
Response: The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		

Organization	Yes or No	Question 6 Comments
Xcel Energy	No	R3 contains a requirement for the PC/TP to provide a copy of its assessment to the RC. This should be eliminated from this standard and merged into R8 of TPL that already requires the PC/TP to distribute the assessment with other entities. R4 - Planning Assessment performed as per TPL-001-4 is applicable to Long-term Planning time horizon (>12 months) and has no overlap with the Operations Planning time horizon (day-ahead to 12 months). Therefore, it is not clear how Planning Assessment would be an appropriate "tool" to address the outage coordination reliability objective in R4 in the Operations Planning time horizon.
Response: The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Dominion Compliance Policy	No	In R2, the Dominion suggests changing the word "function" to "roles and responsibilities" to match R1 Suggested Wording: "R2: Each Transmission Operator and Balancing Authority shall perform the functions roles and responsibilities specified in its Reliability Coordinator outage coordination process."
Response: The SDT does not believe that the suggested change adds clarity. No change made.		
CenterPoint Energy Houston Electric LLC	No	In regards to Requirements R3 and R4, CenterPoint Energy feels the SDT has misinterpreted Paragraph 90 of the NOPR. CenterPoint Energy interprets the language in Paragraph 90 as speaking to the Reliability Coordinator's role in outage coordination in the operational planning horizon. Paragraph 90 mentions generation outages being scheduled 3-5 years in advance and transmission outages being scheduled 1-3 years in advance as part of the planning process. Paragraph 90

Organization	Yes or No	Question 6 Comments
		goes on to mention the need for the Reliability Coordinator, in operational planning, to re-evaluate these planned outages through "... a month-ahead, week-ahead, and sometimes even a day-ahead approval process." CenterPoint Energy does not interpret Paragraph 90 to involve the Reliability Coordinator in the 1-5 year Near Term Planning Horizon process, but to follow its outage coordination process developed in R1.3 and R1.4 to evaluate any previously planned outages within its Wide Area and coordinate resolutions of identified outage conflicts in the Operations Planning Horizon. CenterPoint Energy recommends deletion of Requirements R3 and R4.
MidAmerican Energy Company	No	MidAmerican understands the SDT's intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don't believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. MidAmerican suggests the following language: Each Planning Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
Response: The SDT disagrees, and believes that the Reliability Coordinator may have valuable input into the resolution of potential conflicts. The SDT has revised the rationale for Requirements R3 and R4 to point to the IERP recommendations as well as the FERC NOPR. No change made. However, the SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		

Organization	Yes or No	Question 6 Comments
PacifiCorp	No	PacifiCorp cannot agree to the proposed new standard without having an understanding of the "Reliability Coordinator outage coordination process". Additionally, PacifiCorp needs to understand how the Reliability Coordinator will resolve identified outage conflicts. PacifiCorp cannot support the proposed change of the Violation Risk Factor in R3 from Low to Medium.
Response: The SDT believes that processes may differ in different areas, and therefore defers some specifics to the RC's outage coordination process document. No change made. VRF responses are handled in Q11.		
CPS Energy	No	Propose the following: Strike "Near-Term Transmission Planning Horizon" from Purpose; TPL-001-4 R1.1.1 already requires the model to represent known outages of generation or Transmission Facilities with a duration of at least six months. If outages with a duration of less than six months are required, then this should be a revision to the TPL standard. Strike "4.5. Transmission Planner" from Applicability: All requirements related to the Transmission Planner are either redundant to the TPL-001-4 standard or should be incorporated therein. Strike all of requirement R3: This requirement is redundant to the TPL-001 R8 requirement, since for ERCOT, the Planning Coordinator is the same as the Reliability Coordinator. If it cannot be stricken, then there should be a qualifier that states "this requirement only applies if the Planning Coordinator is NOT the same as the Reliability Coordinator". Otherwise, the Transmission Planner in the ERCOT system is subject to double-jeopardy regarding this standard and the TPL-001 standard. Strike all of requirement R4: If it is required that the Planning Coordinator, Transmission Planner and Reliability Coordinator all have to work together to jointly develop solutions for planned outages less than 6 months in duration, then this should be reflected in the TPL-001 standard. In general, introducing standards that impose requirements on the Planning Assessment should all be incorporated in the

Organization	Yes or No	Question 6 Comments
		TPL-001 standard as opposed to several disjointed standards, which creates confusion and possible redundant and double-jeopardy situations. Regarding R3 & R4, in general Paragraph 90 perspective is misinterpreted & should be limited to next day (not up to 1-year).
Oncor Electric Delivery LLC	No	Proposed Standard IRO-017-1 R3 states: "Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators." Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
Response: The SDT does not intend to imply changes to the approved TPL-001-4 outage inclusion criteria. Proposed IRO-017-1 Requirement R4 requires that any identified conflicts be resolved in coordination with the Reliability Coordinator. No change made. The SDT notes that approved TPL-001-4 does not specifically require communication of the Planning Assessment to the Reliability Coordinator, and therefore proposed IRO-017-1 Requirement R3 is not redundant. However, the SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	R2/M2 - Make Reliability Coordinator in Requirement R2 and Measure M2 possessive. The requirement should read '...in its Reliability Coordinator's outage coordination process.' R4 - To focus the coordination effort of the Reliability Coordinator on BES issues we recommend modifying the wording of R4 to state '...for identified issues or conflicts on the BES with planned outages...'
Response: R2/M2 – The SDT agrees with this comment and has update the language as suggested.		

Organization	Yes or No	Question 6 Comments
R4 – The SDT does not believe this change is necessary as all standards are written for the BES unless stated otherwise. No change made.		
Salt River Project	No	Salt River Project (SRP) has a general concern with the R1 requirement for the Reliability Coordinator to develop, implement and maintain an outage coordination process for generation and Transmission outages. Specifically, SRP is concerned if the RC will have the ability to approve or deny outages.
Response: The Reliability Coordinator already has approval authority and responsibility to cancel planned outages in order to address reliability. Proposed IRO-017-1 Requirement R1 requires the Reliability Coordinator to have an outage coordination process that defines roles and responsibilities for outage coordination within its Reliability Coordinator area. No change made.		
South Carolina Electric and Gas	No	In R2, the OC Review Group suggests changing the word “function” to “roles and responsibilities” to match R1. Suggested Wording: “R2: Each Transmission Operator and Balancing Authority shall perform the functions roles and responsibilities specified in its Reliability Coordinator outage coordination process.” In R4, the OC Review Group suggests adding “on the BES” before “with planned outages” to clearly define the BES as the subject portion of the system. Suggested Wording: “R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.”
Response: The SDT does not believe that the suggested change adds clarity. No change made. R4 – The SDT does not believe this change is necessary. No change made.		
New York Independent System Operator (NYISO)	No	See IRC/SRC Comments. The NYISO also would like to suggest the in R1, generation be replaced with generator to be consistent with R1.1.3

Organization	Yes or No	Question 6 Comments
Response: See IRC/SRC response. The SDT agrees that the language should be consistent and has changed Requirement R1 Part 1.1.3 to 'generation'. See summary for wording.		
Puget Sound Energy	No	The effective date for requirements R1 and R2 should be staggered (similar to the drafting team's approach to requirement R1 and R2 of IRO-010-2). It will be very difficult for a BA or TOP to comply with the RC's outage process if that process is finalized on or near the effective date for requirement R2. Requirement R2 is too broad and should be limited to "performing the applicable functions" of the RC's outage coordination process. In addition, what will happen in the case that the RC specifies deadlines or processes that a BA or TOP cannot meet or requirements that are unrelated to outage coordination? To address this issue, in part, the RC should be required to collaborate with the BAs and TOPs in its area during the development of and revisions to the outage coordination process. This may not address all the issues that could arise, but would at least provide BAs and TOPs with time to address shortcomings in their processes prior to incurring a standard violation.
Response: The SDT disagrees that a staggered approach is needed. These items are not going to be created in a vacuum and the SDT believes that the entities involved will be coordinating as the process is developed. No change made. R2 – The SDT does not believe that the suggested change adds clarity. No change made.		
Flathead Electric Cooperative, Inc.	No	This standard seems unnecessary and I do not support it. The obligations are already covered in other standards.
Response: The SDT disagrees and believes that this standard addresses currently existing gaps. The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		

Organization	Yes or No	Question 6 Comments
Lincoln Electric System	No	To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4.R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
NV Energy	No	We understand the SDT's intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don't believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. We suggest the following language: Each Planning Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Southern believes that Requirement 4 should provide clear guidance that the Planning Coordinator and Transmission Planner are responsible for initiating the review of solutions with their Reliability Coordinator and additional language should be added to clarify that the joint discussions should only be focused on issues that may impact the Operations Planning Horizon. Southern proposes the following revision to the requirement: "Each Planning Coordinator and Transmission Planner shall coordinate with its respective Reliability Coordinator to jointly develop solutions for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, which may ultimately impact the Operations Planning Horizon."

Organization	Yes or No	Question 6 Comments
MRO NERC Standards Review Forum	Yes	To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4.R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
Response: The SDT does not believe there is harm in requiring that the Planning Assessment be shared with impacted Reliability Coordinators, even if no outage conflicts are identified. No change made.		
Duke Energy	No	While we are open to the suggestions made by the SDT, if the scope of RC is going to be expanded, we believe revisions to the Function Model need to occur first and then distributed to the industry for review and approval. The Functional Model is the foundation for the development of Reliability Standards used by Standard Drafting Teams. As indicated above, these revisions to the Functional Model need to occur first before a substantial change in roles and responsibilities of Functional Entities take place within the standards. R1: No comments R2: Duke Energy suggests the following revision: "Each Transmission Operator and Balancing Authority shall perform the roles and reporting responsibilities specified in its Reliability Coordinator outage coordination process." The use of "roles and reporting responsibilities" in the place of "functions" better aligns with the language used in R1.1 of the proposed standard. R3: No comments R4: Duke Energy suggests the following revision: "Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon." We believe "identified issues or conflicts on the BES" better aligns with the intent of this

Organization	Yes or No	Question 6 Comments
		requirement and adds clarity that the RC, PC, and TP will jointly develop solutions for conflicts on the BES.
Response: The SDT does not believe that the functional model needs to be revised prior to approving these changes. R2 – The SDT does not believe that the suggested change adds clarity. No change made. R4 – The SDT does not believe this change is necessary. No change made.		
BC Hydro		The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP's and BA's follow. The responsibility for coordination should reside with the TOP's and BA's, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA's responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage

Organization	Yes or No	Question 6 Comments
		analysis. An RC driven coordination process does not account for differences and needs of TOP's and BA's, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA's responsibility for assessment of system wide conflicts through study assessment, and development of conflict resolution processes to support operations
Response: These requirements were developed in response to IERP recommendations. The SDT believes that processes may differ in different areas, and therefore defers specifics to the Reliability Coordinator's outage coordination process document. The Transmission Operators and Balancing Authorities should participate in the development of the Reliability Coordinator outage coordination process. The SDT sees no conflicts with a Transmission Operator/Balancing Authority process as long as it is coordinated with the Reliability Coordinator process. No change made.		
ACES Standards Collaborators	Yes	(1) We appreciate the drafting team's consideration of previous comments and subsequent revisions.
Seattle City Light	Yes	
Florida Municipal Power Agency	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 6 Comments
Peak Reliability	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Hydro-Quebec TransEnergie	Yes	
Texas Reliability Entity	Yes	
City of Tallahassee, TAL	Yes	
Consumers Energy Company	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Ameren	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

Organization	Yes or No	Question 6 Comments
Northeast Utilities	Yes	
PJM Interconnection	Yes	

Response: Thank you for your support.

7. **Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT deleted 'Operations Planning' from all time horizons concerning Operating Instructions as Operating Instructions are issued in Real-time environments.

The SDT has made the following changes due to industry comments:

R1. Each Transmission Operator shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its ~~e~~Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known ~~other~~ impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of sustained outages of telemetering ~~equipment,~~and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of ~~planned~~ sustained outages of telemetering ~~equipment,~~and control equipment, monitoring and assessment capabilities, and associated communication channels . 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. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall monitor the following as necessary for determining SOL exceedances in its Transmission Operator Area:

10.1 Within its Transmission Operator Area:

10.1.1 Facilities,

10.1.2 ~~t~~The status of Special Protection Systems, and

10.1.3 ~~sub-100 kV facilities~~Non-BES facilities identified as necessary by the Transmission Operator ~~, within its Transmission Operator Area~~

and

10.2 Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

10.2.1 Facilities,

10.2.2 Status of Special Protection Systems, and

10.2.3 Non-BES facilities.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, ~~to ensure~~in order for ~~that~~ it ~~is~~to be able to perform its reliability functions.

R15. Each Transmission Operator shall inform its Reliability Coordinator of ~~its~~ actions taken to return the system to within limits when a SOL has been exceeded.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and ~~Real-time Assessment~~analysis capabilities.

R18. Each Transmission Operator ~~and Balancing Authority~~ shall ~~always~~ operate to the most limiting parameter in instances where there is a difference in SOLs.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area~~(Balancing Authority Area)~~.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its ~~Transmission Operator Area (~~Balancing Authority Area~~)~~.

The SDT has made the following non-substantive changes to other standards for consistency:

TOP-003-3 Requirement R1 Part 1.1: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data as deemed necessary by the Transmission Operator.

IRO-001-4 Requirement R1: Each Reliability Coordinator shall act~~, or direct others to act, by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

IRO-002-4 Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

IRO-010-2 Requirement R1 Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Organization	Yes or No	Question 7 Comments
City of Austin	No	City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments: (1) AE continues to disagree with the change to R1, which removes the "responsibility and clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to "act, or direct others … to act" while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. (2) AE understands the SDT's intent in including the Operations Planning time horizon with respect to Operating Instructions is to cover the concept of "next day directives" previously in IRO-004-2. However, IRO-004-2, as written is limited to RC directives. AE suggests the SDT remove the Operations Planning Horizon from R1. (3) R9 is too broad a scope to be useful. The phrase "…outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels…" is all encompassing. If each BA or TOP were to contact the RC every time there was the slightest glitch with telemetering or every time an ICCP link or microwave channel was cycled for maintenance or some type of momentary signal fade, the RC's phone would be ringing continually. The intent of

Organization	Yes or No	Question 7 Comments
		this requirement is to be sure all entities are aware of a loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 is sufficient to meet the intent. See suggested wording below: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. (4) R19 and R20 are redundant with existing COM standards. They will remain redundant when future COM standards come into effect. AE requests the SDT remove these added requirements from TOP-001-3.
Response: (1) The SDT disagrees that such a requirement is still needed in today's environment. However, the SDT has revised the wording of Requirements R1 and R2 to provide clarity. See summary for wording. (2) The SDT has removed Operations Planning from the time horizon of all requirements dealing with Operating Instructions as those instructions are Real-time oriented. (3) The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made. (4) The SDT does not agree that Requirements R19 and R20 are redundant with anything in the proposed COM standards. No change made.		
South Carolina Electric and Gas	No	With regard to R13, we understand and support the need to do real-time assessments at least once every 30 minutes to avoid being in an unstudied state. However, if significant SCADA losses occur or an ICCP link is lost to a neighboring BA/TOP, the State Estimator solution can be affected to such a degree that a real-time assessment, with real-time data, may not be possible within 30 minutes. While this does not happen often, it does occur on occasion, but the requirement allows for NO exceptions to the 30 minute requirement. (As an example. the MOD-001 standard

Organization	Yes or No	Question 7 Comments
		allows for a certain number of hours that ATC may not be recalculated without being in non-compliance).
Response: The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. For the specific example cited in the comment, the SDT believes that entities have several different methods for resolving the situation. One (and the preferred method) is to notify whomever is cited as providing capabilities pursuant to approved EOP-008-1 and let that entity take over the analysis. Another possible route to take would be to have the operator do an assessment of the system. This could involve the operator studying the Real-time data, the alarm subsystem, system topology, etc., to see if anything has changed since the last assessment. The operator could also call out to other Transmission Operators and the Reliability Coordinator to see if they have noticed anything through scans or analysis that should be taken into account. Once the operator has done this, he/she could provide an assessment of the situation using their professional judgment and chart a course of action as necessary or simply 'certify' that everything is status quo from the last Real-time Assessment. The operator should then communicate the findings as appropriate while recording this information, as well as an indication as to how the assessment was made, in the Operator Log. While the SDT believes this approach is less than optimal, and can't be sustained for a long period, as long as the system hasn't significantly changed, it should be acceptable for a period to cover a short-term 'glitch'. No change made.		
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated. R9 states:"R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." To be consistent with IRO-008-2 R4, where

Organization	Yes or No	Question 7 Comments
		‘NERC registered’ has been struck (also struck in TOP-002-4), Dominion suggests ‘NERC registered’ also be struck in R9 in TOP-001-3.
Response: The SDT has replaced the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording. The SDT has eliminated ‘NERC registered’ from the requirement for consistency. See summary for wording.		
ACES Standards Collaborators	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG’s finding’s a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 should be revised by removing the words “direct others to act” and stating that the TOP shall issue Operating Instructions to ensure reliability of its TOP Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the TOP shall act or direct others to act by issuing an Operating Instruction, the TOP is limited to only this option. We recommend alternative language for this requirement, “Each TOP shall act or issue Operating Instructions to ensure reliability of its TOP Area.”

Organization	Yes or No	Question 7 Comments
		(3) Requirement R1's language of requiring the RC to "ensure reliability" could be used as a zero defect standard if there is an event. "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." Requirement R2 should be revised by removing the words "direct others to act" and stating that the BA shall issue Operating Instructions to ensure reliability of its BA Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the BA shall act or direct others to act by issuing an Operating Instruction, the BA is limited to only this option. We recommend alternative language for this requirement, "Each BA shall act or issue Operating Instructions to ensure reliability of its BA Area." (4) Requirement R2's language of requiring the RC to "ensure reliability" could be used as a zero defect standard if there is an event. "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." (5) Requirements R3, R4, R5 and R6 should be revised to remove the LSE function. (6) For Requirements R10 and R11, we recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (7) Requirement R10 is also problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term "Facilities."

Organization	Yes or No	Question 7 Comments
		(8) We appreciate the clarification that Requirement R13 is not intended to require a Transmission Operator to have state estimation and real-time contingency analysis. We recommend revising the RSAW to ensure that auditors will review events to avoid this standard being zero defect. (9) We appreciate the clarification for Requirement R18 that derived limits are SOLs and have removed the GOP from this requirement. (10) Requirements R19 and R20 have a parenthetical (Balancing Authority Area) that should be removed to avoid confusion. If both TOP Area and BA Area are intended, please list both without parentheses.

Response: 1. As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made.

2. The SDT agrees and has revised the wording of the requirement. A corresponding change was made to Requirement R2 for consistency. See summary for wording.

3 & 4. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.

5. See response to item 1.

6. As previously stated, if the change in term is approved, there will be a project to go through all of the applicable standards to make the needed correction. No change made.

7. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording.

8. The SDT recognizes your comment and will forward the comment to the responsible party.

Organization	Yes or No	Question 7 Comments
9. Thank you for your support. 10. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Georgia Transmission Corporation	No	(1) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which are not performed to “ensure the reliability” of the BES, such as scheduled outages for maintenance items and new construction, etc. The DP and LSE implement Operating Instructions on non-BES equipment on a routine basis, but the implementation of Operating Instructions on BES or non-BES equipment “to ensure the reliability of the BES” is not very routine. Based on the stated purpose of the standard, GTC believes this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. We believe that the use of the NERC term “Emergency” would properly capture the stated intent of this standard. GTC proposes the language “[during an Emergency]” be added after “....shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] “. Based on the stated purpose (which we believe is adequately captured by the use of the term “Emergency”), at a minimum, Operating Instructions issued to ensure the reliability of the BES should be the only Operating Instructions covered by this standard (as was done in R1 and R2). As is currently written Operating Instructions for scheduled outages associated with maintenance items and new construction will also be in scope which conflicts with the stated purpose of this standard. (2) Based on the functional model, the TOP is responsible for the Real-time operating reliability of its Area and has the authority to ensure that its TOP Area operates reliably. Thus, it is clear to us that part of the job of the TOP and/or BA to ensure that the Operating Instructions they issue are performed. Recipient entities such as the DP would rely on the TOP or BAs voice recordings as evidence which is duplicative to what the TOP or BA is already collecting. We would suggest the following:R3: Each Transmission Operator is to verify each Operating Instruction it issues as a part of R1 is completed, unless informed that such action cannot be physically implemented or

Organization	Yes or No	Question 7 Comments
		it would violate safety, equipment, regulatory, or statutory requirements. R4: Each Balancing Authority is to verify each Operating Instruction it issues as a part of R2 is completed, unless informed that such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. An additional benefit to writing the requirements in this manner is a substantial reduction in redundant administrative record-keeping. TOPs and BAs will already be collecting such information as a part of R1 and R2, so requirements along the lines of those proposed above would provide the additional benefit of preventing duplication of records between multiple entities, keeping records of these Operating Instructions performed with the TOP and BA.
Response: (1) The purpose of the standard is to prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences. It is not practical for Transmission Operators to direct switching on the distribution system to prevent such occurrences. However, Transmission Operators would direct Distribution Providers and Load-Serving Entities to perform functions identified in the Functional Model, such as Load shed or voltage reduction to prevent or mitigate such occurrences. The SDT does not believe that the present wording of the requirement places any entity in undue jeopardy or strays from the stated purpose of the standard. The SDT does not believe that constraining the requirement to only be applicable during Emergencies is a viable alternative. Non-Emergency situations can lead to Emergencies and the purpose of issuing an Operating Instruction during those non-Emergency situations is to avoid potential Emergencies down the road. No change made. (2) The SDT does not agree that the responsibility for monitoring these activities should be the sole responsibility of the Transmission Operator or Balancing Authority. Consistent with responsibilities defined in the Functional Model, Distribution Providers and Load-Serving Entities would also need to maintain evidence of such mitigation action as Load shed or voltage reduction. No change made.		
Texas Reliability Entity	No	1) Requirement R8: Texas RE disagrees with the addition of the word “known” to impacted TOPs and BAs. Within the interconnected system, a TOP may not always know who is impacted. It would be prudent to also notify TOPs who may be impacted. We suggest the SDT keep the original language “impacted Transmission Operators.” Requirement R9 did not add “known” to the phrase “impacted interconnected NERC registered entities” which is inconsistent with R8. Texas RE

Organization	Yes or No	Question 7 Comments
		recommends that R8 and R9 should be consistent when the SDT determines if "known" should be included or not. 2) Requirement R9, M9 and R9 VSL: Suggest the SDT remove "NERC registered" to be consistent with other standards in this project. 3) Requirements R9 and M9: The two paragraphs need to be consistent and cover both planned and unplanned outages. Texas RE recommends changing the two paragraphs so that "outages" is preceded by "planned and unplanned." 4) Requirement R10: The use of the term "within its Transmission Operator Area" in R10 may lead to potential conflicts and reliability gaps, specifically for monitoring of SPS's. For example, an SPS owned by a GO/GOP would not have to be monitored by a TOP since it is not within its Transmission Operator Area (i.e. the generator is not a "Transmission" asset per the definition), even though the operation or misoperation of the SPS may lead to SOL violations within the TOP area. Texas RE suggests clarifying language be added by the SDT to assure that a TOP monitors all facilities and Special Protection Systems within its area; not just those that fall under the definition of transmission asset. 5) Requirement R10: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality. The SDT may also consider modifying the language to state "identified as necessary by the Transmission Operator or Reliability Coordinator." 6) Requirements R13, R14, R15: Texas RE requests the SDT consider whether there should be a similar requirement for a BA to perform a Real-time Assessment. The following questions are submitted to assist the SDT's assessment of our request. In

Organization	Yes or No	Question 7 Comments
		real-time, how will a BA control frequency or know if it is experiencing or about to experience a capacity emergency unless it is performing such an assessment? For R14, how does the BA initiate its Operating Plan for an EEA unless it sees a capacity deficiency through a Real-time Assessment? For R15, how does the BA notify the RC of a capacity emergency unless it sees a capacity deficiency through a Real-time Assessment? 7) Requirement R19: The term "(Balancing Authority Area)" appears to be a typo and should be removed. 8) Requirement R20: The term "Transmission Operator Area (Balancing Authority Area)" appears to be a typo and should be replaced with "Balancing Authority Area."

Response: 1) The SDT added the term 'known' based on industry feedback for the exact reasons Texas Reliability Entity is requesting the term to be removed. The addition of the term 'known' reinforces that the Transmission Operator only needs to notify Transmission Operators/Balancing Authorities that are recognized as being impacted through the analysis functions it is performing. However, the SDT has removed 'other' for consistency and clarity.

2) VSL comments are handled in q11.

3) The SDT agrees and has revised the wording to eliminate 'planned' from the Measure which means that both planned and unplanned outages are included. See summary for wording.

4) The SDT believes that the Special Protection System cited would be considered a transmission asset regardless of ownership and would be monitored by the Transmission Operator as part of this requirement. However, the SDT has modified Requirement R10 based on industry feedback for clarity. See summary for wording.

5) Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording.

6) The SDT does not believe that the Balancing Authority can perform a Real-time Assessment given the proposed definition. Nor does the SDT believe that the Balancing Authority needs to perform a special assessment in order to fulfill its responsibilities. There

Organization	Yes or No	Question 7 Comments
are mechanisms already in place in the BAL standards that allow the Balancing Authority to monitor and react to the proposed situations. In addition, the Reliability Coordinator and Transmission Operator would be monitoring the system and coordinating with the Balancing Authority as needed. No change made. 7) & 8) The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Independent Electricity System Operator	No	a. During the last posting, we expressed a concern over the ambiguity in R9 as the phrase “between the affected entities” can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, we suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities b. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
Response: a. The SDT does not agree with the commenter’s interpretation of the requirement wording and believes that it is clearly stated that the communication is only between the affected entities. No change made. b. The SDT has already made NERC management aware of the need for a future project to separate the Transmission Operator and Balancing Authority requirements into separate standards.		

Organization	Yes or No	Question 7 Comments
Associated Electric Cooperative, Inc. - JRO00088	No	R1 and R2: The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI. Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: “Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area.” AECI agrees with SPP comments regarding R10:R10 - We have concerns with the existing language in Requirement R10 which when applied in the real-world of today’s audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn’t model enough of the neighboring TOP’s Area? Isn’t this really the function of the RC and aren’t we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: Each Transmission Operator shall monitor the following to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.10.1 Facilities within its TOP Area 10.2 Status of Special Protection Systems identified as applicable by the Transmission Operator 10.3 Sub-100 kV facilities identified as

Organization	Yes or No	Question 7 Comments
		applicable by the Transmission Operator, and 10.4 Facilities within neighboring Transmission Operator Areas identified as applicable by the Transmission Operator
Response: The SDT agrees and has made the suggested changes. See summary for wording. The SDT has modified the language of Requirement R10 for clarity. See summary for wording.		
Flathead Electric Cooperative, Inc.	No	Again, DPs should not have evidence requirements when the BA/TOP is recording the other end of the line. Suggest deleting "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 in electronic or hard copy format." from any DP measure.
Response: The SDT does not agree that the responsibility for monitoring these activities should be the sole responsibility of the Transmission Operator or Balancing Authority. Consistent with responsibilities defined in the Functional Mode, DP and LSE would also need to maintain evidence of such mitigation action as load shed or voltage reduction. No change made.		
American Transmission Company, LLC	No	ATC requests the SDT to consider making the following changes to the proposed Requirement R10 based on the corresponding technical rationale. It is ATC's understanding that the intention of the SDT is to not require each Transmission Operator to monitor all Facilities and all Special Protection Systems in the neighboring TOP areas. However, the structure of the sentence in Requirement R10 does not provide this clarity. Rather, the sentence requires each TOP to monitor all Facilities, all Special Protection Systems and a subset of sub-100kV facilities for its TOP area and its neighboring TOP areas. If the TOP is to be given discretion on which neighboring Facilities and Special Protection Systems are to be monitored, then ATC suggests that Requirement R10 be modified as:"R10. Each Transmission Operator shall determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area by monitoring: R10.1 Within its Transmission Operator Area: R10.1.1 Facilities R10.1.2 Status of all Special Protection Systems R10.1.3 Sub-100 kV facilities identified as necessary by the Transmission Operator R10.2 Within neighboring Transmission Operator Areas and

Organization	Yes or No	Question 7 Comments
		identified as necessary by the Transmission Operator: R10.2.1 Facilities R10.2.2 Status of Special Protection Systems R10.2.2 Sub-100kV facilities" Please Note: ATC also requested via the RSAW Feedback Form to modify the RSAW's evidence listing for proposed Standard TOP-001-3 to address inconsistencies with the language of Requirement R10 or any modifications to this language based on ATC's comments. For example, if the R10 language is left unchanged, the Facilities evidence should be "all Facilities within its TOP area and those Facilities in neighboring TOP areas determined necessary by the TOP." This structure would also be applied to Special Protection Systems. For sub-100kV facilities, the evidence should be "those sub-100kV facilities determined necessary by the TOP" without a need to reference its TOP area or neighboring TOP areas since that is the plain reading of the requirement.
Response: The SDT has re-structured the requirement for greater clarity. See summary for wording.		
BC Hydro	No	BC Hydro's concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of "Operating Instructions" broadens to non-emergency situations. Requirement R3 and R4 have the BA's complying with TOP's Operating Instructions. BC Hydro's concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no "out" clause based on reliability conflicts - such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an "out" clause.
Response: If an entity wishes to set up an additional higher level of communications, as is apparently intended through the use of Reliability Directive, that entity is free to do so as long as it properly documents the process and continues to follow the COM-002-4		

Organization	Yes or No	Question 7 Comments
established protocols. As far as the definition of Reliability Directive is concerned, the SDT believes that the FERC NOPR clearly stated that the approach proposed in previous projects was not acceptable. Furthermore, the SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. No change made. The SDT believes that entities already have established processes for conflict resolution and that the Reliability Coordinator can always be called upon to adjudicate if needed. No change made.		
Bonneville Power Administration	No	BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, "... operations that result in, or could result in, an Emergency." It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard conflates events that are actually happening with events that may happen at some point. BPA suggests the drafting team clearly separate these two concepts. Specifically, R8 requires entities to identify "... operations that result in, or could result in, an Emergency," without any qualification for likelihood. BPA does not feel it is appropriate to treat an actual Emergency the same way it treats a possible future Emergency that could, but likely will not happen.
Response: The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		

Organization	Yes or No	Question 7 Comments
The SDT believes that the standards need to be taken as a whole and that Requirement R8 refers to Real-time Assessments as well as Operational Planning Analysis results both of which can point to potential problems. Examples of emergent conditions that could result in an Emergency are notification of “stuck breaker”, pending equipment failure or de-rates, or notification of relay degradation. No change made. The SDT believes that likelihood of occurrence is not an issue here. Transmission Operators should make the notifications so that others are informed of the possibility and can take appropriate actions as dictated by internal policies. The SOL White Paper further defines acceptable BES performance and mitigating strategies to control pre-contingency and post-contingency SOL exceedances. No change made.		
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy feels Requirement R1 is general and may provide double jeopardy with other requirements that dictate specifics on when and under what circumstances TOPs are required to act and direct others to act. CenterPoint Energy suggests reverting back to authoritative language requiring TOPs giving its Operating Personnel the authority to act, or direct others to act: “Each Transmission Operator shall provide its Operating Personnel with the authority to act, or direct others to act...” Another suggestion is to delete the Requirement completely due to its broad generality which is already included in the Functional Model, while keeping R3 and R4 for accountability of any Operating Instructions from the Transmission Operator to be followed. CenterPoint Energy also feels the language in R1, “...to ensure the reliability of its Transmission Operator Area” puts an unavoidable burden on the TOP for when an unexpected event occurs. CenterPoint Energy suggests changing ‘ensure’ to ‘maintain’. These comments would also apply to IRO-001-4, R1. R10. CenterPoint Energy feels monitoring Facilities reaching into a neighboring Transmission Operator Area needs more direction. The term ‘as necessary’ is too vague for a TOP to determine how far into a neighboring Area or what specific equipment contained in another TOP Area it would need to monitor to determine SOL exceedances.

Organization	Yes or No	Question 7 Comments
		CenterPoint Energy also feels it is the RC function to monitor and determine any reliability issues which may overlap or cascade between TOP Areas as they have the Wide Area view. CenterPoint Energy recommends removing 'neighboring areas' from R10.
Response: The SDT does not believe there are other requirements in the standards that would produce a double jeopardy situation with Requirement R1. The SDT also believes that Requirements R1 and R3 (as well as Requirements R2 and R4) are a logical and consistent presentation of the use and need for Operating Instructions. The SDT did modify Requirements R1 and R2 based on industry feedback. See summary for wording. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Corresponding changes were made to proposed IRO-001-4. See summary for wording. The SDT believes that the Transmission Operator is in the best position to judge what is necessary and that credit needs to be given to the Transmission Operator's professional judgment in this area. No change made. Monitoring of neighboring facilities does not mean that the Transmission Operator is now taking control of overlap issues from the Reliability Coordinator. The SDT believes that the Transmission Operator's models require information from neighboring systems in order for Operational Planning Analysis and Real-time Assessments to solve accurately. Specifically, a Transmission Operator needs to monitor the status and flows of neighboring Facilities that if outaged could adversely impact its Transmission Operator Area. The SDT has re-structured the requirement for greater clarity. See summary for wording.		
HHWP	No	Draft 2 has not satisfactorily addressed the circumstances of small transmission operators. Most small TOPS operate very simple and predictable systems, with the capacity for only minimal impacts on the BES. Draft Requirement TOP-001-3, R13 which will require such TOPs to perform, review and document real-time assessments every 30 minutes, unnecessarily burdens such TOPs with additional process, expense and resource requirements that will contribute no added reliability above and beyond the real-time assessment processes which Reliability Coordinators already have in place

Organization	Yes or No	Question 7 Comments
Response: The requirement allows for an entity to arrange for another entity to perform the assessment which would alleviate any resource burdens on smaller entities. The SDT believes that the Real-time Assessment for small Transmission Operators with simple and predictable systems would be minimal under normal operating conditions. No change made.		
Ingleside Cogeneration , LP	No	ICLP believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in TOP-001-3 R3 through R6. In R3-R6, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on TOP-001-3's requirements to execute an Operating Instruction - and not so much COM-002-4's oversight of the protocols to use. However, an Operating Instruction can be any communication to "change or preserve the state, status, output, or input" of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to TOP-001-3, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with "this is a mandatory Operating Instruction" should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome - particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.

Organization	Yes or No	Question 7 Comments
Indiana Municipal Power Agency	No	IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow. What happen to results-based standards? Just keeping the telephone logs in many instances will not be enough and it will require much more documented evidence to show that an entity followed the TOP's Operating Instructions. If a Generator Operator is asked to change MW/VAR output or asked to maintain the same output numerous times in a day by its Transmission Operator, it will have to keep evidence to show that it carried out every single Operating Instruction throughout the entire day. Does this mean keeping track of the output of the Generator for the day and giving the entire log to the auditor to show the Generator Operator carried out each Operating Instruction?
Response: The SDT believes that complying with Operating Instructions is extremely important for the reliability of the system and that emphasis in audits will be on whether the Operating Instruction was followed as opposed to a missing log entry. The SDT suggests that the commenter's points would be better submitted in the RSAW process for proposed TOP-001-3. The current RSAWs instruct the auditor to focus on EOP-004 reportable events. No change made.		
Hydro-Quebec TransEnergie	No	In R4, modify the second "its Transmission Operator" by "that Transmission Operator" for consistency with the wording of R6. Also modify corresponding element in the Table of Compliance Elements. In R9 and M9, remove the expression "interconnected NERC registered" for consistency with IERP recommendation regarding TOP-002-4 R3 In R17, replace "analysis" by "Real-time Assessment" for consistency with R16. R18 is unclear. What does "where there is a difference in SOLs" mean? Difference in SOLs compared to which SOL? A "difference" implies a comparison between two SOLs. That portion of the requirement should be clarified. The rationale for R19 and R20, which are related to data exchange capabilities, states that they're added for consistency with IRO-002-4 R2 whereas R2 addresses RC's System Operator authority.

Organization	Yes or No	Question 7 Comments
		In R19 and R20 why the use of "Transmission Operator Area (Balancing Authority Area)" for both requirements? R19 should say "Transmission Operator Area" and R20 should say "Balancing Authority Area" for consistency with associated Measures. Compliance section 1.2: As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R8 and R9 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. Example: "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted Transmission Operators or other known impacted Balancing Authorities that the Responsible Entity did not inform of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas or Balancing Authority Areas when conditions did permit such communications :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" The whole wording of the requirement could be omitted for more clarity :"Violation Severity Levels for requirement 8 are determined based on the number of other known impacted entities that the Responsible Entity did not inform in accordance with that requirement :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.

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Response: The SDT does not believe that the suggested change adds any clarity. No change made. The SDT agrees and has made the suggested change. See summary for wording. The Balancing Authority does not perform Real-time Assessments per the proposed definition but does perform other analyses that are defined in the BAL standards. Therefore, the SDT believes that the current wording is correct. No change made. The requirement applies to the instance where differing Transmission Operators, for some unknown reason, are working off of different SOLs for the same equipment. The SDT believes that the wording is clear and has been understood by the industry. However, the SDT has deleted the Balancing Authority from the requirement. See summary for wording. The rationale box contained a typo which has been fixed. The correct reference is proposed IRO-001-4 Requirement R1. The SDT has corrected the typo in requirements R19 and R20. See summary for wording. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. VSL comments are handled in Q11. How the SOL Exceedance White Paper will be included is to be determined by NERC staff. It may be a hyperlink or it may be the inclusion of the entire paper.		
Xcel Energy	No	In R7, how is the entity receiving the request able to know if the requesting entity has indeed implemented its emergency procedures? Suggest removing that qualifier, or change the requirement to state that “Each Transmission Operator shall assist Transmission Operators experiencing an Emergency, if requested, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.” R10 is not written clearly. Suggest restructuring. Each Transmission Operator shall monitor: o Facilities (including sub-100 kV facilities needed to maintain reliability) within its Transmission Operator Area and o Facilities (including sub-100 kV facilities needed to maintain reliability) in neighboring Transmission Operator Areas to

Organization	Yes or No	Question 7 Comments
		maintain reliability within its Transmission Operator Area o Status of Special Protection Systems within its Transmission Operator Area R16 & R17 should state "...approve or defer/deny..." Is R18 only for derived limits or if there is a difference in any limit? Or is the intent of the requirement to be " ... when limits are derived and there are differences when comparing solutions."?
Response: The SDT believes that the requested Transmission Operator will ascertain whether the requesting entity has implemented its procedures. No change made. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording. The SDT believes that absence of approval by the operator is equivalent to deny and that the additional wording is not necessary. No change made. The language on derived limits was removed in the second posting. The Transmission Operator shall operate to the most limiting SOL at any point in time.		
Consumers Energy Company	No	In Requirement 1 and 2 the term reliability provides a vague stipulation. "... by issuing Operating Instructions to ensure the reliability of its Transmission Operating Area." I don't know if language can be suggested at this point, but I would prefer to see "stability" rather than "reliability".
Response: The SDT believes that 'reliability' is the appropriate term. No change made.		
Puget Sound Energy	No	It is nearly impossible for entities to comply with requirements R1 and R2 of TOP-001-3 as currently drafted. This issue is highlighted (not corrected) by the draft RSAW's approach of evaluating compliance only during events. RSAWs are only guidance -

Organization	Yes or No	Question 7 Comments
		reading footnote 1 of the current RSAW template makes it clear that the RSAW is a reference document only and entities cannot depend on the approach outlined there to resolve ambiguities associated with a requirement. The place to resolve ambiguities is in the standard's language, not in the RSAW. An entity must comply with any requirement at all times; it does not matter if the enforcement authority only checks compliance during certain periods. If an entity fails to comply with the requirement at any other time, that entity is obligated to self-report the violation. In this situation, then, each entity must "ensure" the reliability of its area 24/7/365 to be compliant with requirement R1 or R2. This means that any reliability event could reflect an entity's failure to comply with R1 or R2 because the entity failed to ensure the reliability of its area during that event. But can any entity really ensure the reliability of its area? This just doesn't seem possible because there are so many factors outside of an entity's control that can affect the reliability - for example, equipment failure or a fire along transmission lines. In addition, the burden of monitoring compliance based on the proposed language is immense. Requirements R1 and R2 of the currently effective TOP-001-1a require entities to take action to "alleviate operating emergencies". This is a high bar, but not so high that an entity cannot comply when factors beyond its control affect the reliability of its area. In addition, using this language in the proposed standard would be consistent with the RSAW's approach and ease the associated compliance monitoring obligation, while still requiring an entity to act to protect the reliability of its area.
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified

Organization	Yes or No	Question 7 Comments
		phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. With regard to R13, MidAmerican believes the SDT has improved the language by revisions such that the TOP shall "ensure that a Real-time Assessment is performed at least once every 30 minutes;" however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, MidAmerican suggest the following: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP."
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be		

Organization	Yes or No	Question 7 Comments
supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
Northern Indiana Public Service Company (NIPSCO)	No	NIPSCO feels R10 should align with the Operational Planning Analysis Requirement and include a reason such as "to determine SOL exceedances". NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
Response: Requirement R10 includes the term 'to determine any SOL exceedances". No change made. The SDT does not agree. Proposed COM-001-2 is for interpersonal communications which covers voice communications. The purpose of proposed TOP-003-3 focuses on defining data requirements. The SDT added Requirements R19 and R20 to cover real-time data exchange. No change made. The SDT does not agree. Requirements R16 and R17 are about the Real-time data exchange and analysis capabilities that an operator has at his/her disposal and not about Transmission and generation outages as described in proposed IRO-017-1. No change made.		
PacifiCorp	No	PacifiCorp needs clarification concerning how R16 works in tandem with the Reliability Coordinator outage process noted in IRO-017-1. Additionally, PacifiCorp questions whether we have the ability to compel a non-NERC Registered Entity to provide data in order to maintain reliability in the Transmission Operator Area.

Organization	Yes or No	Question 7 Comments
		Also, inclusion of the Near-term Planning Horizon (which is 1 - 5 years) into the future isn't appropriate. This should be addressed in a revised TPL standard. Does this mean that Planning must coordinate all proposed 6 month (see TPL-001-4 R1 effective on 1/1/2015) or longer outages with the DMCC up to 5 years into the future every X days, months, or annually?
Response: Requirement R16 is about the Real-time data exchange and analysis capabilities that an operator has at his/her disposal and not about Transmission and generation outages as described in proposed IRO-017-1. Standards only apply to NERC registered entities, specifically those entities identified in the applicability section of each standard. PacifiCorp would need to rely on Interconnection or Operating Agreements for authority outside of the NERC Standards. The SDT can only write standards that apply to NERC Registered Entities. The SDT assumes this comment is about proposed IRO-017-1 and not about proposed TOP-001-3 which does not pertain to planning. The inclusion of the Near-Term Transmission Planning Horizon in proposed IRO-017-1 is a direct response to the FERC NOPR and IERP report. As is pointed out in the rationale box for proposed IRO-017-1 Requirement R4, and shown in the second posting inclusion of a draft SAR for future revisions to approved TPL-001-4, the long-term goal is to move appropriate requirements from proposed IRO-017-1 to a future revision of approved TPL-001-4. However, the scope of this project did not allow for changes to TPL standards. Requirement R4 of proposed IRO-017-1 does not state that a planner must coordinate outages – it states that planners must resolve potential conflicts that appear in its assessments and include the Reliability Coordinator in such a process.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 States:"R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." In response to R9, Oncor recommend s that the requirement to make it mandatory for BA's and TOP's to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES.

Organization	Yes or No	Question 7 Comments
		R10 as proposed requires each "Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area". The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001-3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10 be reworded to provide flexibility for region structure. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.

Response: Due to comments received from a number of entities in the first posting, the term 'negatively' was removed as it was open to interpretation and superfluous. The SDT continues to agree with this approach. No change made.

Requirement R10 does not stipulate that an entity install equipment for the purposes of monitoring neighboring Transmission Operator SOLs. Monitoring can be accomplished in a number of ways including utilizing existing data links with its Reliability Coordinator or neighboring Transmission Operators to receive the status of neighboring facilities and associated flows that could impact Facilities within the Transmission Operator Area. The SDT believes that Transmission Operators need such data in order to have its models solve and for its analysis methods to be valid and also believes that the majority of Transmission Operators are

Organization	Yes or No	Question 7 Comments
already doing this to some extent. Therefore, it does not see this requirement as placing any undue burden or cost on Transmission Operators. The SDT has re-structured the requirement for greater clarity based on industry comments. See summary for wording. Based on approved FAC-011-2 Requirement R3, Part 3.7, the Reliability Coordinator has the responsibility to develop an SOL Methodology which includes defining IROL and associated T_v. The Reliability Coordinator is always the arbiter of disputes of this nature. No change made.		
SPP Standards Review Group Kansas City Power & Light	No	R1 - We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Transmission Operator takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R1 specifically to those entities identified in Requirements R3 and R4. We recommend the following rewrite: ’Each Transmission Operator shall act, or direct others as identified in Requirements R3 and R4 to act, by issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.' R2 - We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Balancing Authority takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R2 specifically to those entities identified in Requirements R5 and R6. We recommend the following rewrite: ’Each Balancing Authority shall act, or direct others as identified in Requirements R5 and R6 to act, by issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.' R9 - We feel that the use of impacted interconnected entities is too broad for the notification requirement. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Additionally, the term ‘NERC registered’ in Requirement R9 and Measure M9 should be deleted. This term was deleted in IRO-008-2, Requirement R4 and TOP-002-4,

Organization	Yes or No	Question 7 Comments
		Requirement R3. We recommend rewording the requirement to read: ’Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities lasting 30 minutes or longer.’ Should Requirement R9 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R10 - We have concerns with the existing language in Requirement R10 which when applied in the real-world of today’s audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn’t model enough of the neighboring TOP’s Area? Isn’t this really the function of the RC and aren’t we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: 'Each Transmission Operator shall monitor 10.1 Facilities within its TOP Area,10.2 status of Special Protection Systems identified as necessary by the Transmission Operator,10.3 sub-100 kV facilities identified as necessary by the Transmission Operator, and10.4 Facilities within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator as necessary to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.’ Rationale Box for R14 - The newly inserted sentence in Rationale Box for R14 doesn’t completely present the overall picture of the Operating Plan as contained in the Associated Documents at the back of the standard. We propose an additional sentence, as indicated below, be included in the Rationale Box.’...These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments (OPA) required per proposed TOP-002-4 or

Organization	Yes or No	Question 7 Comments
		other assessments. The Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). The intent is not to have a...’ R18 - Should Requirement R18 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R19 - Delete the parenthetical Balancing Authority in Requirement R19. R20 - Delete Transmission Operator and the parentheses around Balancing Authority in Requirement R20.

Response: The SDT has revised the requirements to delete ‘ensure’ and replace it with ‘address’ as in the first posting. See summary for wording.

The SDT agrees and has revised Requirements R1 and R2 accordingly. See summary for wording.

The SDT has revised the requirement to delete ‘ensure’ and replace it with ‘address’ as in the first posting. See summary for wording.

The SDT believes that the suggested wording is unnecessary redundancy and that it is clear from reading the standard as a whole what entities are applicable. No change made.

The SDT believes the current language accurately reflects the reliability need and absent a suggested replacement sees no reason to change the proposed language. The SDT also believes that the use of the term ‘impacted’ should alleviate concerns over momentary outages as such outages are unlikely to impact others. No change made.

The SDT believes that the professional judgment of the Transmission Operator should be the overriding factor in determining how much of a neighboring system that it needs to monitor with the principal reasoning being to monitor status and flows of key external facilities that impact Transmission Operator Facilities and that any attempt to legislate how far to go is unworkable in a standard. The SDT also believes that some degree of monitoring of neighboring systems is required for models and analysis to work correctly and that Transmission Operators are already doing this type of work. Monitoring does not imply that the Transmission Operator is usurping the wide area responsibilities of the Reliability Coordinator – it only implies that a Transmission Operator must have some

Organization	Yes or No	Question 7 Comments
degree of visibility outside its own footprint in order to fulfill its reliability responsibilities. The SDT has re-structured the requirement for greater clarity. See summary for wording. The SDT agrees and has added the suggested sentence to the rationale box. The SDT does not believe that the suggested change adds clarity. No change made. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R1 and R2 - Southern understands other commenter's concerns about BAs, GOPs, DPs, and LSEs not falling into a Transmission Operator's TOP Area, but Southern disagrees with the approach taken by the SDT to address these concerns. Rather than removing "within its TOP Area" in R1 and "within its BA Area" in R2, the requirement should spell out the entities to link to R4 and R5. Suggested change as follows: R1 - Each Transmission Operator shall act, or direct its Balancing Authorities, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R2 - Each Balancing Authority shall act, or direct its Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure reliability within its Balancing Authority Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R10 begins with 'Each Transmission Operator shall monitor Facilities...' Southern suggest that the words, "Bulk Electric System" be added to R10 so that it reads 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", consistent with the verbiage in IRO-003-2 Requirement 1. Measure 10 should also be changed accordingly. R10 - Southern suggest that utilization of the words, "as necessary" makes the requirement confusing and proposes the below verbiage to add clarity: 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", the status of Special Protection Systems, and sub-100 kV facilities identified by the Transmission

Organization	Yes or No	Question 7 Comments
		Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas, “as being necessary to determine” any System Operating Limit (SOL) exceedances within its Transmission Operator Area.’ Measure 10 should also be changed accordingly. R15 - Southern appreciates the SDT’s consideration of Southern’s comments but disagrees that the Requirement as currently drafted, does not reflect “past tense” with respect to actions taken. Southern suggest that the SDT reword the Requirement for clarification purposes: ’Each Transmission Operator shall inform its Reliability Coordinator of its actions taken to return the system to within limits when a SOL has been exceeded.’
Response: The SDT agrees and has revised the requirements accordingly. See summary for wording. The use of the capitalized term ‘Facilities’ means that the requirement phrase is for the BES. Therefore, the SDT believes that the suggested change would be redundant and possibly create confusion. The SDT has re-structured the requirement for greater clarity. See summary for wording. The SDT received multiple comments concerning Requirement R10 and has re-structured the requirement based on all comments received. See summary for wording. The SDT has made the suggested change for consistency in wording. See summary for wording.		
CPS Energy	No	R1, in general, change to only require TOP to have the authority to act, or direct others to act, R10, in general, regarding monitoring Facilities reaching into a neighboring TOP area needs clarifying...best to delete neighboring areas wording.
Response: The SDT received a number of comments on the wording of Requirement R1 and has revised the language accordingly which should serve to alleviate your concerns. See summary for wording. The SDT has re-structured the requirement for greater clarity based on numerous industry comments. See summary for wording.		

Organization	Yes or No	Question 7 Comments
Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: ”Each TOP shall act or issue Operating Instructions to entities, as necessary, within its TOP Area to ensure the reliability of its TOP Area.” We believe “within its TOP Area” is necessary within the context of the standard. Requirements R3 and R4 appear to imply that Operating Instructions from a TOP are within the bounds of the TOP area only. However, by removing this language, it is our view that the TOP could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R2: Duke Energy suggests re-writing R2 as follows: ”Each BA shall act or issue Operating Instructions to entities , as necessary, within its BA Area, as necessary, to ensure the reliability of its BA Area.” We believe “within its BA Area” is necessary within the context of the standard. Requirements R5 and R6 appear to imply that Operating Instructions from a BA are within the bounds of the BA area only. However, by removing this language, it is our view that the BA could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R3-R6: No Comments R7: While Duke Energy believes that this is a great operational expectation or operating practice for a TOP, we believe that the requirement “as written” is unmeasurable. We believe it will be difficult for an auditor to measure how a TOP verified that another TOP implemented “its emergency procedures”. The term “emergency procedures” is too vague and subject to interpretation. For example, at what point in another TOP’s emergency procedures should a TOP provide assistance? Based on this language, we suggest removing R7 from this standard or adding this to a guidance document to promote operational excellence within the industry. R8: Duke Energy suggests re-writing R8 as follows: ”Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities and other

Organization	Yes or No	Question 7 Comments
		impacted Transmission Operators, of its actual or expected operations that result in, or could result in a known Emergency.” R9-R12: No Comments R13: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an TOP’s Energy Management System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R14-R20: No Comments
Response: The SDT has revised the wording of Requirements R1 and R2 to address your concerns and those of others. See summary for wording. The SDT believes that the requested Transmission Operator will ascertain whether the requesting entity has implemented its procedures as part of normal operations dialogue. No change made. The SDT does not believe that the suggested change adds clarity. No change made. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made.		
American Electric Power	No	R9: The reference “impacted interconnected NERC registered entities” needs to be consistent with the R8 terminology. We request that it be changed to “known impacted interconnected entities”. R10: The reference”sub-100 kV facilities identified as necessary by the Transmission Operator” needs to be clarified. Specifically, the phrase “as necessary” is ambiguous and subject to interpretation. Our negative vote is driven solely by the ambiguous

Organization	Yes or No	Question 7 Comments
		reference “sub-100 kV facilities identified as necessary by the Transmission Operator”.
Response: The term ‘NERC registered’ has been deleted. See summary for wording. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. However, the SDT believes that the Transmission Operator is the only one who can determine which non-BES facilities it needs to monitor and any attempt to mandate a specific coverage would be unworkable. See summary for wording.		
Northeast Power Coordinating Council Hydro One	No	Regarding Requirements R1 and R2, “ensure” should not be used as mentioned in previous comments. This must be honored THROUGHOUT the standard. For this particular requirement, consider using the word “maintain” or “restore” instead. Throughout the standard, consider replacing “address” with “maintain”. The Time Horizon should not include Operations Planning, or Same-Day Operations. The phrase, ‘within its TOP/BA Area’ should not be removed. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. Regarding Requirement R3, Time Horizons should not include Operations Planning, or Same-Day Operations. Regarding ALL the standard’s requirements, where Operating Instruction is used, the Time Horizon category must be reviewed. In Requirement R7, the “e” in emergency must be capitalized. “Comparable” should be added before “assistance”. In R7, the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it

Organization	Yes or No	Question 7 Comments
		from the previous requirements. To address the Drafting Team response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. The previous language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency. In Requirement R9, strike the words “interconnected NERC registered” to be consistent with TOP-002-4 Requirement R3. The language in Requirement R16 should be made consistent with the language in Requirement R9. There should be consistent language used in requirements R9, R16, and R17. During the last posting, a concern was expressed over the ambiguity in R9 as the words “between the affected entities” can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities. Regarding Requirement R10, a Transmission Operator cannot be held responsible for monitoring ANY facilities in neighboring Transmission Operator areas. A Transmission Operator can only rely on what information is provided by a neighboring Transmission Operator. The new requirement R19 addresses the data exchange capabilities needed. The Drafting Team should consider removing R10. If Requirement R10 is to remain, then if a sub-100 kV facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an

Organization	Yes or No	Question 7 Comments
		authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP's entire area when in reality a subset of facilities may be all that is required. One suggested rephrasing is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area... Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. The Drafting Team should consider removing "ensure" or its replacement word from Requirement R11. Refer to standard PRC-001-1.1. Requirement R13 should be reworded to: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The "s" in system should be capitalized in Requirement R15. The word "own" should not be deleted from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. "Always" should be removed from Requirement R18. In Requirement R19 "(Balancing Authority Area)" is not needed and should be removed. In Requirement R20 remove "(Balancing Authority Area)" and "Transmission Operator Area". What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility several Transmission Operator Areas away from a Transmission Operator Area impacts that Transmission Operator Area.

Organization	Yes or No	Question 7 Comments
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. The SDT has deleted Operations Planning from the Time Horizon for all requirements in this standard as Operating Instructions are issued in a Real-time environment. However, the SDT believes that Same-Day Operations are sufficiently Real-time oriented and has retained that term. The SDT believes that the wording of Requirement R3 as currently stated is correct. However, due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording. The SDT agrees and has capitalized the 'e' in Emergency. See summary for wording. However, the SDT does not agree with the return of 'comparable'. The SDT believes that this term is unmeasurable and open to interpretation. The SDT has revised Requirement R9. See summary for wording. The SDT does not believe that there needs to be a one-to-one correspondence between the language in Requirements R9, R16, and R17 as they are addressing different topics. No change made. The SDT does not believe that the suggested change adds clarity to Requirement R9. No change made. The SDT has revised the wording of Requirement R10 concerning sub-100 kV facilities to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. The SDT has also re-structured the requirement for greater clarity. See summary for wording. However, the SDT disagrees that the current wording requires a Transmission Operator to monitor all of its neighbor's facilities. The SDT has removed 'ensure' from the requirement. See summary for wording. The SDT does not believe that the suggested change adds clarity to Requirement R13. No change made. As 'System' includes distribution as per the definition in the NERC Glossary, the SDT disagrees that 's' should be capitalized. No change made. The SDT continues to believe that 'own' is superfluous and is not needed in the requirement language. No change made. The SDT agrees that 'always' is superfluous and provides no value or clarity. See summary for wording. The SDT has corrected the typo in Requirements R19 and R20.		

Organization	Yes or No	Question 7 Comments
The SDT believes that a Transmission Operator is in the best position to determine how far out it needs to go, i.e., what its neighbors are. The SDT agrees that events several areas away can impact an entity and for that reason has used 'neighbors' instead of 'adjacent'. The professional judgment of the Transmission Operator should determine what a neighbor is.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration. 1. Requirement R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator in its notification protocol] of its inability to perform an Operating Instruction issued by its Transmission Operator..." 2. Requirement R6 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority in its notification protocol] of its inability to perform an Operating Instruction issued by that Balancing Authority."
Response: The SDT believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes it cannot implement the instruction(s) for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT agrees that an Operating Instruction may include a timeframe given by the Reliability Coordinator, but defining a generic timeframe is not necessary, or appropriate, for a requirement. No change made.		

Organization	Yes or No	Question 7 Comments
Seattle City Light	No	SCL appreciates the efforts of the Standard Drafting Team to increase the clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation. However for TOP-001-3, SCL believes a changes are required before this Standard provides the clarity and effectiveness of the others. Specifically SCL asks for changes as follow: Requirement R9 covers too broad a scope to be useful. The phrase "...outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels..." is all encompassing. If each BA or TOP was calling the RC every time there was the slightest glitch with telemetering or every time an ICCP link, microwave channel or EIDE data signal was cycled for maintenance or some type of momentary signal fade, the RC's phone would be ringing continually. The intent of this requirement is to be sure all entities are aware of a loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 (as written, but also see below) is sufficient to meet the intent. SCL suggests the following re-wording:R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of any scheduled and sustained outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. Requirement R13, SCL suggests changing 30 minutes to 60 minutes. Usually generation, load and interchange are estimates and adjusted on hourly basis so performing assessment every 30 minutes is not necessary and could prove an onerous requirement for TOPs without providing any real reliability benefits. SCL suggests the following re-wording:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 60 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made.

Organization	Yes or No	Question 7 Comments
The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
Electric Reliability Council of Texas, Inc.	No	Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: "Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term "Operating Instruction" outside of real time. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.

Organization	Yes or No	Question 7 Comments
Response: The SDT disagrees that such a requirement is still needed in today's environment and the proposed revision is consistent with recommendations in the IERP report. Furthermore, the SDT believes that the suggested wording does not add clarity to the situation and may actually create confusion as there are too many objectives being covered in one sentence. However, the SDT has revised the wording of Requirements R1 and R2 to address industry comments. See summary for wording. The SDT does not understand the comment as written and is unable to find a comment from ERCOT for proposed IRO-008-2 for this topic. The SDT agrees and has deleted Operations Planning from Time Horizons for all requirements dealing with Operating Instructions. The SDT has already informed NERC management of the need for a future project to separate the Balancing Authority from the TOP standards.		
New York Independent System Operator (NYISO)	No	The NYISO has a concern with the term ensure. We suggest revising the phase to, 'maintain the reliability of it's...' R1/R2: The NYISO does not support the removal of the phrase, ' within it's TOP/BA Area'. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. R7: The NYISO continues to believe the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it from the previous requirements. To address the SDT response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. Our proposed language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency.

Organization	Yes or No	Question 7 Comments
		R13: The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes were based on the requirements to be within IROL's in 30 minutes. The 30 minute assessment for SOL's may be too limiting. R16: The NYISO suggests retaining the work 'own'. This would provide clarity that this in only about the equipment the TOP owns and not other equipment. R19/20: The SDT should clarify the purpose of the bracketed entities (Balancing Authority)? The NYISO believes that R19 should be focused on TOP and R20 should be focused on BA.
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording. The SDT does not believe that the suggested change adds clarity to Requirement R3. No change made. The SDT has capitalized the 'e' in Emergency to provide additional clarity. See summary for wording. The SDT does not agree and believes that the requested Transmission Operator will discuss what procedures the requesting Transmission Operator has put in place as part of normal operating dialogue in these situations. No change made. The SDT does not agree that this requirement should be limited to IROL evaluations. The FERC NOPR made it clear that Transmission Operators should be performing SOL evaluations as well. The SDT wants to reinforce that a Real-time Assessment does not imply that all identified SOL exceedances need to be resolved within 30 minutes. SOL exceedances need to be mitigated consistent with the Transmission Operator's Operating Plan as highlighted in the SOL Exceedance White Paper. IROL exceedances would need to be mitigated consistent with the IROL T_v. No change made. The SDT disagrees and considers the adjective as unnecessary in this context. No change made. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
NV Energy	No	The SDT has made a number of improvements to this particular standard in this latest posting. We are troubled by the following items: Definition of Real-Time Assessment contains two provisions that will make compliance with the Requirements

Organization	Yes or No	Question 7 Comments
		unattainable. First, the applicable inputs to the assessment include among other things, “known Protection System status or degradation.” Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation. Secondly, the real time assessment is to consider “identified phase angle and equipment limitations.” We are unclear as to whether this is intended to mean the identification of post-contingent standing phase angles (which current RTCA tools are ineffective at modelling and assessing) or alternatively, the identification of the angular limitations of power system equipment, such as sync check permission settings for circuit breakers. Such analyses are more readily conducted using on line power flow tools, and do not lend themselves to the real-time environment. We understand that the insertion of the modifier “applicable” may provide some relief in these considerations, but we fear that compliance enforcement will not allow discretion as to what inputs are applicable and which are not. We appreciate the significant improvement with regard to the language in Requirement R10.With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would suggest the following: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform with this R13 language.

Response: The inclusion of phase angle and Special Projection Scheme status is based on FERC NOPR and Southwest Outage recommendations. The SDT felt it was more prudent to include these items as part of the Real-time Assessment definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of Protection Systems and/or phase angles. Modeling and assessment of Special Protection Schemes and/or phase angles would be supported by Operating Plans. For

Organization	Yes or No	Question 7 Comments
example, an Operating Plan could instruct those performing a Real-time Assessment to enable/disable specific Contingencies that reflect Special Protection Scheme status (in-service or out-of-service).No change made. An entity can only provide data and information on what it has available and the addition of the term ‘applicable’ was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made.		
Tennessee Valley Authority	No	There should be more than one level of VSL. As currently written there seems to be no allowance for instances where entities may be operating at two different ratings (i.e. temperature-dependent ratings, directional ratings, etc.) or a period of time before the entities coordinate which rating should be used in real-time.
Response: VSL comments are addressed in q11.		
Peak Reliability	No	There still needs to be clarity about conflicting Operating Instructions. For example, if TOP 1 gives and Operating Instruction to TOP 2 and then TOP 3 gives an Operating Instruction to TOP 2, which one trumps? The same would be true for BAs. This creates potential conflicts for TOPs, BAs, and RCs. "within its ... Area" should not have been removed. R9: Why restrict to NERC registered entities when this term was removed from other requirements throughout the IRO/TOP revisions? R13: Should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.

Organization	Yes or No	Question 7 Comments
Response: The SDT does not believe that a Transmission Operator can deliver an Operating Instruction to another Transmission Operator. Such instructions would have to be provided by a Reliability Coordinator. However, due to your comment and those of others, the SDT has restored the language concerning ‘within a Transmission Operator/Balancing Authority Area”. See summary for wording. Requirement R9 has been corrected. See summary for wording. The SDT does not believe that a requirement is necessary for this issue and that it can, and will, be handled through the measure for this requirement. No change made.		
Colorado Springs Utilities	No	We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following are our additional comments above and beyond what SPP's comments are. R13 - Would a tool such as a state estimator or RTCA be required to meet the Real-time Assessment definition or can it be done without “real-time” tools? Your response to our previous comments allude to the fact that all entities are currently using or contracting for such “real time” tools which is not universally true. Additional implementation period is needed and thus requested due to the time needed for budgeting and implementation of “real time” tools.
Response: The requirement does not specify how an entity will accomplish the task. RTCA would be one method but there are others. And, the requirement leaves open the possibility of aligning with a third-party to accomplish the task. Therefore, the SDT does not believe that additional implementation time is required. No change made.		
IRC Standards Review Committee	No	We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the

Organization	Yes or No	Question 7 Comments
		BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
Response: The SDT has already informed NERC management of the need for a future project to separate the Balancing Authority from the TOP standards.		
Western Area Power Administration	No	Western has a concern on the use of the word ensure in R1 and R2. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the TOP, in R1, or BA, in R2, didn't provide instructions that ensured the reliability of its area. We would suggest changing the last portion of R1 to '.... issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.' and the last portion of R2 to '....issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.'
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording.		
Florida Municipal Power Agency	Yes	In R16 and R17, FMPA suggests replacing the words "to approve" with "over" to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators. In R16, FMPA suggests replacing "Real-time Assessment" with "analysis" to be consistent with the similar requirements for the RC and BA.FMPA notes that the number of contingencies to be studied is absent from the definition of Real-time Assessment, see comments on TOP-002-4.
Response: The SDT does not believe that the suggested change adds clarity. No change made. The SDT agrees and has used 'analysis' for consistency. See summary for wording. See response to TOP-002-4 for other considerations.		

Organization	Yes or No	Question 7 Comments
FRCC Operating Committee (Member Services) City of Tallahassee, TAL	Yes	The FRCC Operating Committee supports a majority of these proposed requirements. However, the OC does not support the language in new requirement R9 and finds that the mapping from current requirement (TOP-003-1 R3) is incomplete and needs to be addressed by the standard drafting team. The language in the existing TOP-003-1 R3 is more precise and should remain as is. If the SDT is attempting to address the comments from the SW Outage Report Recommendations “TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities,” they should create a separate requirement to reflect the notification for loss of Real-time Assessment capabilities. At a minimum, the requirement should state “telemetering and control equipment”, rather than “telemetering equipment, control equipment”. This will add clarification to the type of equipment being addressed in the requirement. In addition, the word “planned” from M9 was not removed as noted in SDT responses. We also recommend removing the words “interconnected NERC Registered”. The word “impacted” reflects who should be notified. The current mapping of existing TOP-003-1 R3 to TOP-001-3 R9 does not accurately reflect the original intent of TOP-003-1 R3. R19 and R20 have some inconsistencies with referencing TOPs and BAs.
Response: The SDT believes that the current language accurately reflects the intent of the requirement and is an accurate representation of existing requirements. However, the SDT agrees with the suggested change regarding telemetering and control equipment. See summary for wording. ‘Planned’ and ‘NERC registered’ have been removed from the measure. See summary for wording. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		

Organization	Yes or No	Question 7 Comments
Ameren	Yes	We are concerned that an entity may have a reportable NERC violation if Contingency Analysis is down for more than 30 minutes.
Response: The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
MRO NERC Standards Review Forum	Yes	We believe that requirement R9 to notify impacted entities of planned outages of telemetering equipment, control equipment, and monitoring and assessment capabilities is too broad. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Therefore, we propose the following revision to R9: R9 Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted entities of "planned outages" of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities lasting 30 minutes or longer. Requirements R16 and R17 require that TOP and BA give authority to their system operators to approve planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Using the same rationale of R9, we propose to revise R16 and R17 as follow: R16 Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its monitoring, telecommunication, and Real-time Assessment capabilities. R17 Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its monitoring, telecommunications, and analysis capabilities. Similarly, IRO-002-4 requirement R2 should also be revised as follow: R2 Each Reliability Coordinator shall provide its System Operators with the authority to

Organization	Yes or No	Question 7 Comments
		approve planned outages and maintenance last 30 minutes or longer of its telecommunication, monitoring and analysis capabilities.
Response: The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made. The SDT does not believe that the suggested change adds clarity. No change made.		
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
Response: Thank you for your response.		

8. **Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

R5. Each Balancing Authority shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s).

Organization	Yes or No	Question 8 Comments
PacifiCorp	No	: PacifiCorp cannot support the standard as proposed with the removal of the term NERC Registered from R3 and R5 given that the obligation to notify non-NERC Registered entities introduces an element of uncertainty into our notification obligations. Also, does next day require DMCC changes for Saturdays and Sundays? At least Operating Plan Analysis seems to allow for next-day analysis. Is the intention to mandate 24/7 rotating staff in control rooms?
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made. The SDT can't tell any entity how to do its job. It can only write requirements. In this case, the SDT believes that it is important for reliability to have a valid next-day analysis available. How an entity accomplishes this is up to them.		
Texas Reliability Entity	No	1) Requirement R4: Texas RE reiterates our previous comments regarding adding a new requirement for the BA to have an Operational Planning Analysis (in line with R1

Organization	Yes or No	Question 8 Comments
		language for the TOP). The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion. 2) Requirement R6: Texas RE requests the SDT consider whether the TOP should also be required to provide its Operating Plan(s) for next-day operations to the BA. The following questions are submitted to assist the SDT's assessment of our request. Without the TOP Operating Plan, how will a BA perform its assessment of delivery capability if it does not have predicted or planned transmission outages from the TOP(s)? 3) Requirement R7: Texas RE requests the SDT consider whether the BA should also be required to provide its Operating Plan(s) to TOPs. Without the BA Operating Plan, it is unclear how a TOP will perform its assessment to determine if there will be any SOL exceedances if it does not have the predicted generation dispatch and demand patterns from the BA.
Response: 1) The SDT does not believe that the Balancing Authority can perform an Operational Planning Analysis given the proposed definition. Nor does the SDT believe that the Balancing Authority needs to perform a special analysis in order to fulfill its responsibilities. There are mechanisms already in place in the BAL standards that allow the Balancing Authority to monitor and react to the proposed situations. In addition, the Reliability Coordinator and Transmission Operator would be monitoring the system and coordinating with the Balancing Authority as needed. No change made. 2) Since the Transmission Operator's Operating Plan may contain confidential Transmission information that a Balancing Authority can't see, the SDT believes that submittal of the plan to the Reliability Coordinator is the correct mechanism. If there are situations that arise where there are potential conflicts between the plans of the Transmission Operator and Balancing Authority, the SDT believes that the role of the Reliability Coordinator, both in this standard and in proposed IRO-017-1, will take care of those situations. In addition, the SDT points to proposed TOP-003-3 in which Transmission Operators and balancing Authorities can exchange information through the data specification concept. No change made. 3) See response to item 2. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	In R1, the OC Review Group suggests adding the word "identified" before "SOLs" to clarify transmission operators are operating to the identified SOLs. Suggested

Organization	Yes or No	Question 8 Comments
South Carolina Electric and Gas		Wording: “R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its identified System Operating Limits (SOLs).”
Georgia Transmission Corporation	No	In R1, the GSOC suggests adding the word “identified” before “SOLs” to clarify transmission operators are operating to the identified SOLs. Suggested Wording: “R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its identified System Operating Limits (SOLs).”
Response: The SDT believes the suggestion does not add clarity. No change made.		
Bonneville Power Administration	No	BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement.
Response: The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		
Hydro-Quebec TransEnergie	No	In R1, replace "shall have an Operational Planning Analysis" by "shall perform an Operational..." In R2, replace "as required in Requirement R1" by "performed in requirement R1" for consistency with M2.Do not capitalize "requirement" since it is not a defined term. R6: Why not put that requirement in R2? Simply add "...and provide that plan to its Reliability Coordinator" to the end of R2 (same for R7). The standard would be more clear and concise.

Organization	Yes or No	Question 8 Comments
		Compliance section 1.2: As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements : See comment made for TOP-001-3 Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: R1 – The SDT disagrees. The present wording allows for an entity to use an existing Operational Planning Analysis if it is still pertinent. The SDT believes this flexibility relieves the entity of a possible undue burden. The suggested language would not allow for such flexibility. No change made. R2 – The SDT believes the present wording is correct given the explanation in item 1 above. It is standard procedure in Reliability Standards to capitalize the word 'Requirement' when it is used within a requirement. No change made. R6 – The SDT believes that the suggested consolidation would create a single requirement that contains two actions (a compound requirement) which SDT Guidelines state should be avoided. No change made. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. See response to TOP-001-3. The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		
Florida Municipal Power Agency	No	It seems the SDT did not understand FMPA's previous comment regarding R1. FMPA's comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase "N-1 Contingency planning" no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the TOP's OPA supposed to consider

Organization	Yes or No	Question 8 Comments
		N-2 events? N-3? Loss of an entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase “in accordance with its RC’s SOL Methodology”. Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards.
Response: The SDT does not want to be overly prescriptive. The Transmission Operator has the obligation to preserve the reliability of the interconnected Transmission system. The Contingencies to be handled in an Operational Planning Analysis are laid out in the Reliability Coordinator’s SOL methodology and the SDT expects that an entity will adhere to that methodology when performing its Operational Planning Analysis. No change made.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU’s etc.) or phase

Organization	Yes or No	Question 8 Comments
		angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. Removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3 opens the requirement scope to an un-provable state and potential non-compliance. MidAmerican suggests the modifier “NERC registered” be restored in front of “entities.”
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term ‘applicable’ was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term ‘NERC registered entities’ is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: ”Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any identified System Operating Limits (SOLs).”We believe the addition of “identified” adds additional clarity and conforms to the language in FAC-011.

Organization	Yes or No	Question 8 Comments
		R2: Duke Energy requests clarification on whether a process for each SOL exceedance identified in the Operational Planning Analysis is necessary or is one document that address any and all exceedances of SOL(s) is acceptable? R3: Duke Energy believes "impacted" is not needed in the context of the requirement and suggests removal. R4: No Comment R5: Duke Energy believes "impacted" is not needed in the context of the requirement and suggests removal. R6/R7:Duke Energy suggests the following for R6:"Each Transmission Operator shall provide the results of its Operating Planning Analysis for next-day operations identified in Requirement R2 to its Reliability Coordinator." We also believe that R6 and R7 goes beyond the scope of Recommendation 1 of the SW Outage Report. The report indicates that TOPs should share the results with neighboring TOPs and RCs, and not necessarily the Operating Plan itself. In addition, the BA is not cited in Recommendation 1 of the SW Outage Report as having to do the same type of analysis.
Response: R1 - The SDT believes the suggestion does not add clarity. No change made. R2 – The SDT outlined its beliefs on this matter in the associated explanation of Operating Plan which appears in Section F of the proposed standard. R5 – The SDT agrees and has made the suggested change. See summary for wording. R6/R7 – The SDT believes that simply providing the results could be potentially misleading and that it would be better for reliability to provide the entire plan. While the SDT agrees that the SW Outage report did not specifically spell out the Balancing Authority, that inclusion of the Balancing Authority is consistent with the over-all approach of the project standards and makes sense for reliability. No change made.		
Xcel Energy	No	R2 - is the descriptor "potential" needed?

Organization	Yes or No	Question 8 Comments
		Do R6 & R7 need a qualifier "...by the time frame established by the RC"?
Response: The SDT believes that since the requirement is dealing with next-day operations that haven't happened, that the use of 'potential' is correct and needed. No change made. The SDT believes that the Transmission Operator/Balancing Authority will coordinate with the Reliability Coordinator as to when the plans need to be submitted and that placing such language in a requirement is unnecessary and could be detrimental. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R3 - It is not clear why the SDT removed the qualifier "NERC registered". Southern recommends adding "NERC registered" back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. R5 - See comment regarding removal of "NERC Registered" for R3. Also, in the SDT's consideration of our previous comments, the SDT states they do not believe R5 requires notification. Given R5 clearly states that the BA shall notify impacted entities, it is not clear what the SDT's expectation / interpretation of this requirement is. Southern suggests modifying the requirement to incorporate the concept that notification from the BA is only required to entities where the BA is requesting an action that is different than what the entity provided to the BA. For example, if a GOP provided their expected generation resource commitment and dispatch to the BA, the BA reviews the information and determines that this particular GOP needed to commit additional units to provide more regulation, frequency response, etc., then the BA should notify this GOP. If another GOP provided data and the BA did not have any suggested changes, then there should not be a notification requirement. Suggested changes are as follows: "Each Balancing Authority shall notify NERC registered entities identified in the Operating Plan(s) cited in Requirement R4 when the BA is requesting the entity to take an action that is different from the last submitted plan the entity originally provided to the BA."

Organization	Yes or No	Question 8 Comments
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made. The SDT disagrees and believes that specific notifications should be delivered for each day's Operating Plan. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	R4 - We suggest that load forecast uncertainty and resource uncertainty be added to the list of Parts for Requirement R4.1.3 Data Retention - Hyphenate 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Response: The SDT believes that uncertainty can be handled within the existing requirement language in Requirement R4, Parts 4.1 and 4.3. No change made. The SDT agrees and has corrected the typos.		
Electric Reliability Council of Texas, Inc.	No	The current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4.For R4, the SDT should consider consistency of use of "Demand patterns" and "Load Forecast".
Response: See response to IRO-008-2 comment. Without a specific reference for consistency, the SDT believes that the current language is correct. No change made.		
Northeast Power Coordinating Council Hydro One	No	The proposed definition for Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a redline of what is in the NERC Glossary. The Rationale for Requirement R1 can be removed, and be placed in a guideline or support document.

Organization	Yes or No	Question 8 Comments
		The Rationale for Requirement R3, and Rationale for Requirements R4 and R5 can be removed. It belongs in Consideration of Comments. The Rationale for Requirements R6 and R7 can be removed, and be placed in a guideline or support document.
Response: Due to the extensive changes made to the two definitions, the SDT believes that it would have caused considerable confusion if a redlined version had been supplied. No change made.		
Northern Indiana Public Service Company (NIPSCO)	No	TOP-002-4 R1 requires that you perform an analysis that identifies SOL exceedances, but SOLs are not explicitly included as a study input in the Operational Planning Analysis definition, only Facility Ratings, which are only a subset of FAC-014-2 R2 SOLs. There seems to be operating plans created by the TOP in R2 and operating plans created by the RC in IRO-008-2. How are conflicts resolved if the results differ? How does the R2 Operating Plan mesh with the operating plan specified in VAR-001-4 R1? Are they the same?
Response: The SDT believes that if an entity observes its applicable Facility Ratings in pre- and post-Contingency situations that it will avoid SOL exceedances since SOLs are based on Facility Ratings. The SDT believes that there are existing protocols for resolving conflicts and that the exchange of Operating Plans required by these proposed standards facilitate the identification of any potential conflicts and start the conflict resolution process. No change made. The SDT believes that the plan cited in VAR-001-4 Requirement R1 would be one part of the Operating Plan cited in this proposed standard.		
NV Energy	No	We are troubled by the removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3. This unnecessarily opens the requirement scope to an un-provable state. Suggest restoring the modifier “NERC registered” in front of “entities.”

Organization	Yes or No	Question 8 Comments
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
Puget Sound Energy		The language of measure M2 is inconsistent with requirement R2 - it is missing the word "exceedance" after the phrase "System Operating Limits (SOLs)".
Response: The SDT agrees and has made the suggested change to ensure consistency. See summary for wording.		
MRO NERC Standards Review Forum Lincoln Electric	Yes	As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the Plan is modified or not. To prevent unnecessary duplication as well as allow for greater flexibility in the requirement, recommend modifying R6 as follows to allow the Transmission Operators and Reliability Coordinators to develop an arrangement or schedule.R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator in accordance with the Reliability Coordinator's schedule.
Response: The SDT disagrees with the commenter's statement. The present wording allows for an entity to use an existing Operational Planning Analysis if it is still pertinent. The SDT believes this flexibility relieves the entity of a possible undue burden. The suggested language would not allow for such flexibility. No change made.		
Ameren	Yes	Our Daily Analysis supplements the MISO Operational Planning Analysis and although we could rely on MISO, we have chosen to go beyond what is required.
Seattle City Light	Yes	
ACES Standards Collaborators	Yes	
NERC Compliance Policy	Yes	

Organization	Yes or No	Question 8 Comments
IRC Standards Review Committee	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 8 Comments
Independent Electricity System Operator	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

9. **Do you agree with the changes made to respond to industry comments to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1, Part 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data as deemed necessary by the Transmission Operator.

Organization	Yes or No	Question 9 Comments
ACES Standards Collaborators Georgia Transmission Corporation	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 is problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term "Facilities."

Organization	Yes or No	Question 9 Comments
		(3) For Requirements R1 and R2, we recommend changing the term “Special Protection System” to “Remedial Action Scheme” because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (4) Requirement R5 should be revised to remove the LSE function.
Response: (1) As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made. (2) The SDT has clarified its intent in revised wording. See summary for wording. (3) The term Special Protection System remains within the NERC Glossary as an approved term. If at some point in the future, this term is replaced, a change to this standard can and should be proposed to conform it to the new term. No change made (4) As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made.		
Texas Reliability Entity	No	1) Requirement R1.1: Texas RE requests that the SDT consider replacing the term “sub-100 kV” with “non-BES” to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to “sub-100 kV” facilities is for those facilities that have been intentionally included in the BES due to their criticality? 2) Requirement R2: Texas RE reiterates our previous comments about replacing “analysis functions” with “Operational Planning Analysis.” This comment relates to the TOP-002-4, R4 comment for requiring a BA to have an Operational Planning

Organization	Yes or No	Question 9 Comments
		Analysis. The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion.
Response: The SDT has clarified its intent in revised wording. See summary for wording. The SDT considers that "analysis functions" is an adequate description of the Balancing Authority's study process, and considers that the proposed definition of Operational Planning Analysis would require the Balancing Authority to possess information related to Transmission limitations unrelated to the act of balancing Load and resources. There is not reliability gap. No change made.		
Electric Reliability Council of Texas, Inc.	No	Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: This data concerning Protection System status is currently collected routinely and data transfer mechanisms are in place. Twelve months is a reasonable time frame to implement Requirement R3. The SDT assumes that the commenter meant to say Transmission Operator and not Reliability Coordinator. The SDT does not intend for the Transmission Operator to monitor Protection Systems rather the intent is for the equipment owner to notify the Transmission Operator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. No change made.		
Hydro-Quebec TransEnergie	No	Compliance section 1.2 : As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that

Organization	Yes or No	Question 9 Comments
		particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).
Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made.		
Duke Energy	No	Duke Energy asks the SDT to consider adding a mechanism to allow a recipient of a request to challenge the requestor if a reliability related need cannot be established. For example, should a BA wanting to know the ACE of every BA within the Eastern Interconnection be allowed to get this information if there is not a reliability related need to have the information?
Response: The SDT is unconvinced that a requestor will consistently request data that it does not need to assure continued reliability. The SDT understands your concern but this does not rise to the level of a standard requirement. No change made.		
Ingleside Cogeneration , LP	No	ICLP agrees there are times where the TOP will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason - and eliminates the possibility that the TOP can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of TOPs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned TOP - that a full evaluation by an independent panel would take place afterwards.
Response: Requirement R1, part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		

Organization	Yes or No	Question 9 Comments
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term “as deemed necessary” in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of “Section 4 - Measurability” of the NERC document titled Acceptance Criteria of a Reliability Standard states “Words and phrases such as “sufficient”, “adequate”, “be ready”, “be prepared”, “consider”, etc. should not be used.” ReliabilityFirst believes the phrase “as deemed necessary” is such a phrase, which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.
Response: In Requirement R1 Part 1.1, “as deemed necessary” refers to the certain data elements that the Transmission Operator decides is needed. This would not be a measurement component of this requirement, since Requirement R1 Part 1.1 requires the publication of a list, which can be objectively measured during an audit. No change made.		
CPS Energy	No	see comments for IRO-010-2
CenterPoint Energy Houston Electric LLC	No	See comments for IRO-010-2.
Response: See response to IRO-010-2.		
Northeast Power Coordinating Council Hydro One	No	The proposed definitions for Real-time Assessment and Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a red line of what is in the NERC Glossary. Additional information should be added to the Rationale for Requirement R5 for justification and background.
Response: Since the changes to the two definitions were so extensive, the SDT believed it would be confusing to provide a redline version of the definitions. No change made. The SDT believes that the rationale provided is sufficient when taken in conjunction with the NOPR comment. No change made.		

Organization	Yes or No	Question 9 Comments
Salt River Project	No	The Requirements go way beyond the established NERC process in creating and modifying current standards. The goal is stated to create reliability standards that “use a results based approach that focuses on performance, risk management and entity capabilities”. I suggest that the requirements in TOP-003-3 do not meet this threshold in that the burdensome requirements do not result in a significant enhancement in reliability nor do they consider entity capabilities. I suggest that the SDT work on creating a simple and efficient process to verify that necessary operating data is being freely exchanged as needed among entities. A suggestion might be to create a regional committee to address those conflicts that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this Standard.
Response: The need for data to support reliability is unquestioned in a system where multiple Balancing Authorities, Transmission Operators and Reliability Coordinators are coordinating together to preserve reliability. The proposed change would produce delays in securing the data necessary to support preserving reliability. No change made.		
Indiana Municipal Power Agency	No	The use of a documented specification for the data needed by the Transmission Operator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instance where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Transmission Operator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means that Generator Operators in this TOP area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.

Organization	Yes or No	Question 9 Comments
Response: The ability of the Reliability Coordinator to request and receive the data necessary to preserve reliability is a foundation of coordinated system operations. The suggested change would result in an unmeasurable and non-auditable standard. No change made.		
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated.
Response: Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team in crafting IRO and TOP Standards that are clearer while generally reducing the burden of compliance documentation. For TOP-003-3, while somewhat burdensome, this Standard makes the process for requiring entities to request and provide real time reliability data standardized. SCL is concerned with the implementation period allowed for this Standard, because in our experience it has taken longer than 12 months to negotiate and implement the necessary data exchange agreements between entities. As such, SCL suggests extending the periods allowed to eighteen and twenty-four months, re-wording the effective date section as follows: Section 5. Effective Date. All requirements except Requirements R5 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved gy an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R5 shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval

Organization	Yes or No	Question 9 Comments
		by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction
Response: Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
Ameren	Yes	We are concerned about the change from "Planned Outage Coordination" to "Operational Reliability Data" which as we understand deals with the specification and exchange of data for use in studies for which we find the languages confusing and needing clarification.
Response: Planned Outage Coordination is now in proposed IRO-017-1.		
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 9 Comments
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 9 Comments
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	

Organization	Yes or No	Question 9 Comments
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
Response: Thank you for your support.		

10. **Do you have any comments on the changes made to respond to industry comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT reviewed the submitted comments and incorporated most of the suggestions. The SDT believes the suggested changes provided clarity resulting in a better product. Changes can be seen in the redlined version of the SOL Exceedance White Paper.

Organization	Yes or No	Question 10 Comments
IRC Standards Review Committee Independent Electricity System Operator	No	During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT's response indicates that "it has revised the whitepaper to include "as necessary and appropriate". However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that "All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan." We speculate that the insertion of "as necessary and appropriate" to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, "However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating)." We urge the SDT to reassess whether or not the "as necessary and appropriate" should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.

Organization	Yes or No	Question 10 Comments
Response: The SDT agrees and has modified the White Paper as suggested.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	As currently presented, the example Operating Plan in Table 1 on page 8 of the SOL Exceedance White Paper is confusing. It is actually a pretty good attempt to capture in table form the concepts described in the document text related to the time limit is exceeded versus pre-/post- contingency. However, it uses terms such as "non-cost" and "off-cost" which are not standard industry terms and which are not used elsewhere in the document. The SDT should consider removing these terms and using more standard terms, such as re-dispatch reconfiguration, etc. as appropriate. In addition, the "Legend" shown is confusing and does not help support the example.
Response: The SDT agrees and has modified the White Paper as suggested.		
Electric Reliability Council of Texas, Inc.	Yes	During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT's response indicates that "it has revised the whitepaper to include "as necessary and appropriate". However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that "All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan." If there is a basecase exceedance, the entity should take all actions up to and including shedding load within the timeframe to protect the equipment. If the entity is somewhere between the 4 hr. and 15 min. rating they have up to 15 min to get below the continuous (normal) rating for a basecase (pre contingency) exceedance.
Response: The SDT agrees and has modified the White Paper as suggested.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	Yes	Hyphenate 24-hour in the 8th line under 1. on Page 1. First full paragraph on Page 3, we suggest the following rewrite for the last sentence in that paragraph. 'Conversely, if an area is not at risk of instability, no Facilities are

Organization	Yes or No	Question 10 Comments
		approaching their thermal Facility Ratings but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the limiting SOLs.' We also suggest deleting the 1st sentence in the following paragraph on Page 3. The paragraph flows better without it. We further suggest the following rewording in what would then be the 2nd sentence in the paragraph. 'How an entity remains within these SOLs can vary depending on the operating practices and planning strategies employed by that entity.' In 4. Voltage Stability Limits, replace the 2nd sentence with the following: 'Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met.'

Response: The SDT has modified the White Paper to incorporate many of the proposed changes.

24-hour in the 8th line under '1.' on Page 1 has been hyphenated.

As suggested, the last sentence in the first full paragraph on page three has been modified to state, "Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs."

The first sentence in the following paragraph states, "It is important to distinguish operating practices and strategies from the SOL itself." The SDT believes this is an important statement that is critical to conveying the intent of the White Paper. No change made.

The recommendation regarding the second sentence in the in this paragraph proposes to remove the word "mechanisms" and replace it with "planning strategies". The SDT agrees that the addition of "planning strategies" adds clarity to the sentence and will accept the recommended change. However, the SDT believes that "mechanisms" are an important part of how an entity remains within the SOLs as explained in the following sentence in the White Paper. The SDT changed the sentence to state, "How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity."

As suggested, the second sentence in the voltage stability section has been modified to state, "Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met."

Organization	Yes or No	Question 10 Comments
Northeast Power Coordinating Council Hydro One	Yes	In the White Paper System Operating Limit Definition and Exceedance Clarification, delete the phrase “unit/intra-area instability,” from the Transient Stability Limits description. Individual unit instability is not being looked at; operations are to prevent system instability. During the last posting, the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded was commented on. The Drafting Team’s response indicates that “it has revised the whitepaper to include “as necessary and appropriate”. However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that “All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.” We speculate that the insertion of “as necessary and appropriate” to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, “However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating).”We urge the SDT to reassess whether or not the “as necessary and appropriate” should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.
Response: The SDT agrees and has modified the White Paper as suggested.		
New York Independent System Operator (NYISO)	Yes	The current draft introduces the term ‘limiting SOLs’. ’For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or

Organization	Yes or No	Question 10 Comments
		post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the limiting SOLs. Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs. We believe that a better wording would be the 'limiting criteria that results in the identified SOL'.
Response: The SDT does not believe that the phrase 'limiting SOL' introduces a new term, but in order to provide additional clarity, the phrase 'limiting SOL' has been replaced with 'most limiting SOL'. The SDT chose not to adopt the proposed wording, 'limiting criteria that results in the identified SOL'. In the referenced 'for example' sentence, the Facility Ratings are the actual SOLs that are not to be exceeded pre- or post-Contingency consistent with the example provided in Figure 1. In this example scenario, the SDT views the Facility Ratings as being the 'most limiting SOLs' rather than the most 'limiting criteria'. This concept is supported by paragraph 1 on page 7 which states, "An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment: • Actual flow on a Facility is above the Facility Rating for an unacceptable time duration • Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating" No change made.		
American Electric Power	Yes	There are inconsistencies between the information provided in Figure 1 (p.5) and Table 1 (p.8) which may cause confusion. Consider for example the range of 800 to 900 MVA. In Figure 1, the Pre-Contingency flow in this range is considered "not acceptable" if longer than 4 hours. The text "not acceptable" is too strong, so rather than this language, we suggest using "action may need to be taken". The rows in Table 1 do not clearly correspond to the example in Figure 1. It would appear that Table 1 should have four rows rather than three. As a result, it is unclear exactly which of the four ranges in Figure 1 correlate to the three Operating Plans provided in Table. In Figure 1, does the 800mva (24 hr rating) refer to a Normal or Emergency facility rating, or perhaps both? Please provide clarification.

Organization	Yes or No	Question 10 Comments
Response: The phrase 'not acceptable' is simply used to distinguish two possible categorizations of system performance – acceptable versus not acceptable (or unacceptable). Given these two categorizations, in the Figure 1 example, exceeding the 4-hour emergency rating for longer than 15 minutes constitutes unacceptable system performance. The SDT chose to keep the existing language. No change made. There are four operating ranges in Figure 1 and three rows in Table 1. The bottom range in Figure 1 does not have a corresponding row in Table 1 since no Facility Rating is being exceeded in that operating range. Table 1 Row 1 corresponds to the operating range in Figure 1 between 800-900 MVA (between the green and the yellow Facility Ratings). Table 1 Row 2 corresponds to the operating range in Figure 1 between 900-950 MVA (between the yellow and the red Facility Ratings). Table 1 Row 3 corresponds to the operating range in Figure 1 above 950 MVA (above the red Facility Rating). Regarding the nature of the 800 MVA rating, item 1 on page 1 states, "A 24- hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature." No change made to Figure 1.		
FRCC Operating Committee (Member Services) City of Tallahassee, TAL Florida Municipal Power Agency	Yes	We suggest adding the following clarification to page 2 of the white paper: o Remove the terms "Normal (continuous)" from the Pre-Contingency section, example "b". We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. o Remove the terms "Emergency (short term)" from the Post-Contingency section, example "b". We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. We also suggest that the paper be reviewed for consistency when using the terms "pre-contingency" and "post-contingency". Interchanging the use and context causes confusion - i.e. Change the column headers in Table 1, "Pre-Contingency Loading" to "Pre-Contingency Mitigation" and change "Post-Contingency Loading" to "Post Contingency Mitigation". Another example would be to use "Real-Time flow" instead of "Pre-Contingency Flow".

Organization	Yes or No	Question 10 Comments
		Also in Table 1, under the 'Emergency (4hr)" row - "Post Contingency Loading" column change "all" to "available".
Response: The SDT agrees with the suggestion to revise the language on page 2 in item 'b' under the pre-Contingency section and item 'b' under the post-Contingency section to state "All Facilities shall be within their applicable Facility Ratings and thermal limits". This change is justified by the subsequent clarifications in the White Paper along with the Figure 1 example which illustrates an SOL performance summary for Facility Ratings. Note 1 in Figure 1 clarifies that pre-Contingency flow is the actual MVA flow observed on the Facility through Real-time operations monitoring. The SDT reviewed the paper and verified the accuracy of the use of "pre-Contingency" and "post-Contingency". The SDT chose to maintain Table 1 column headings as "Pre-Contingency Loading" and "Post-Contingency Loading" since the purpose of the mitigation strategies contained within the table are to control loadings. However, the SDT agrees with changing "all" to "available" in Table 1, "Post-Contingency Loading" column, "Emergency (4 hr.)" row.		
Duke Energy	Yes	Duke Energy agrees with the SOL Performance Summary described in Figure 1. We believe that Figure 1 adequately describes the intent on treatment of SOL(s), more so than the text of the White Paper itself. We suggest that the SDT revise the text in the White Paper to better align with the SOL Performance Summary in Figure 1.
Response: The SDT believes the White Paper is most effective through the combination of text, tables, and figures. The SDT is willing to process specific feedback regarding White Paper text.		
Peak Reliability	Yes	The SOL Whitepaper directly addresses the confusion, debates, and misconceptions around the SOL concept that is so prevalent in the industry. Many thanks to the SDT for issuing the much needed SOL Whitepaper. Peak believes this paper will not only bring clarity and resolution to confusing and even contentious issues related to SOL establishment and exceedance, but will also result in improved reliability.
Seattle City Light	No	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards.
Associated Electric Cooperative, Inc. - JRO00088	No	

Organization	Yes or No	Question 10 Comments
ACES Standards Collaborators	No	
NERC Compliance Policy	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Clark Public Utilities	No	
Flathead Electric Cooperative, Inc.	No	
CenterPoint Energy Houston Electric LLC	No	
Manitoba Hydro	No	
Pepco Holdings Inc.	No	
Idaho Power Company	No	
American Transmission Company, LLC	No	
Northern Indiana Public Service Company (NIPSCO)	No	
Texas Reliability Entity	No	
Salt River Project	No	
Consumers Energy Company	No	
Oncor Electric Delivery LLC	No	
ReliabilityFirst	No	
Tennessee Valley Authority	No	

Organization	Yes or No	Question 10 Comments
Tri-State Generation and Transmission Association, Inc.	No	
Northeast Utilities	No	
Georgia Transmission Corporation	No	
CPS Energy	No	
MidAmerican Energy Company	No	
Response: Thank you for your support.		

11. **The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements and to respond to industry comments. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.**

Summary Consideration: The SDT corrected several typos and made a grammatical change to all VSLs dealing with notification. As was pointed out in a comment, the 'syntax' of the proposed VSLs was incorrect. Instead of saying 'lesser than' it should have said 'greater than' to allow for the proper consideration of the violation. Due to the simple replacement of one word or because it was just a simple typographical correction and the volume of changes, the actual changes are only shown in the redlined standards.

The SDT has made the following changes to VSLs in response to industry comments:

IRO-008-2:

R3	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted ~~NERC registered~~ entities identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).

IRO-008-2: Requirement R4 Severe VSL - ~~The Reliability Coordinator did not perform Real-time Assessments. OR~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.

IRO-014-3:

R2	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address one of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address two of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address all three of the ~~criteria~~parts specified in Requirement R2.

IRO-014-3: Requirement R7 Severe VSL - The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator ~~has~~had implemented its emergency procedures, unless such actions could not physically be implemented or would have violated safety, equipment, regulatory, or statutory requirements.

IRO-017-1: Requirement R2 Severe VSL - The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator's outage coordination process.

TOP-001-3: Requirement R1 Severe VSL - The Transmission Operator failed to act~~, or direct others within its Transmission Operator Area to act,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

TOP-001-3: Requirement R2 Severe VSL - The Balancing Authority failed to act~~ or direct others within its Balancing Authority Area to act,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

TOP-001-3: Requirement R7 Severe VSL - The Transmission Operator did not provide assistance to other Transmission Operators, ~~if~~when requested and able, ~~when~~and the requesting entity had implemented its ~~e~~Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

TOP-001-3: Requirement R8 Severe VSL - The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators~~, whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more ~~other~~ known impacted Balancing Authorities or more 15% of the known impacted ~~other~~ Balancing Authorities~~, whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.

TOP-001-3: Requirement R9 Severe VSL - The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, monitoring and assessment capabilities, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more impacted interconnected NERC registered entities or more than 15% of the negatively impacted NERC registered entities~~, whichever is less,~~ of a planned outage of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

TOP-001-3

R10		N/A	~~N/A~~ The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.2.	~~N/A~~ The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities. ~~identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area~~

TOP-001-3: Requirement R13 Severe VSL - The Transmission Operator did not perform Real-time Assessments. OR, ~~-~~For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for ~~three~~four or more 30-minute periods within that 24-hour period.

TOP-002-4

R3	The Transmission Operator did not notify one impacted entity or 5% or less of the impacted entities, whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted ~~NERC~~entities or more than 10% and less than or equal to 15% of the impacted entities, whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more impacted ~~NERC~~entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two ~~impacted~~ entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more ~~impacted~~ entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).

TOP-003-3:

R5	~~N/A~~ The responsible entity receiving a data specification in	The responsible entity receiving a data specification in	The responsible entity receiving a data specification in	~~The responsible entity receiving a data specification in~~

	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~one~~two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~two~~three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	~~Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).~~ ~~OR,~~ The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

Organization	Yes or No	Question 11 Comments
City of Austin	No	The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. That is, the moderate level should be lower, the high should be moderate and the first half of severe should be high.

Response: The SDT agrees as the VSLs for proposed TOP-003-3 and proposed IRO-010-2 should agree and the VSLs for proposed IRO-010-2 are based on VSLs for approved IRO-010-1. See summary for wording.

Organization	Yes or No	Question 11 Comments
Texas Reliability Entity	No	1) IRO-008-2, Requirement R4 VSLs - Suggest the SDT remove "NERC registered" to be consistent with the Requirement R4 language and other standards in this project. The words were removed once in the VSLs but they occur twice in the VSLs. 2) IRO-008-2, Requirement R6 VSL - Texas RE requests the SDT consider revising the R6 VSL to contain only a Severe VSL. Texas RE submits that any failure to notify of IROL or SOL exceedances could result in cascading outages. 3) TOP-001-3, Requirements R8 and R9 VSLs - Texas RE recommends removing each instance of the phrase "whichever is less" from the R8 and R9 VSLs or at least from the Severe VSLs. At worst, it appears to nullify intent stated by the SDT for R8 and R9 that a situation where a small entity did not inform just one affected entity should be a Severe violation. At best, it adds no clarity to assessing violation severity levels. Specifically, for R8, if a small TOP with 1 known impacted other TOP did not notify that impacted TOP then it's 100% which should make it a Severe VSL. However, the phrase "whichever is less" appears to kick it back to a Lower VSL because it is only one failure to inform, not four or more, which is less. It's important to note that TOP-002-4, Requirements R3 and R5 do not include the phrase "whichever is less" in the Severe VSL language which is presumably a recognition that it doesn't apply in the Severe VSL. 4) TOP-002-4, Requirements R3 and R5 - Texas RE recommends removing each instance of the phrase "whichever is less" from the R3 and R5 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs. 5) TOP-003-3, Requirements R3 and R4 - Texas RE recommends removing each instance of the phrase "whichever is less" from the R3 and R4 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 11 Comments</th></tr>
<tr><td></td><td></td><td>6) IRO-010-2, Requirement R2 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R2 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs.

TOP-001-3: Requirement R9, M9 and R9 VSL: Suggest the SDT remove “NERC registered” to be consistent with other standards in this project.</td></tr>
<tr><td colspan="3">Response: 1) The SDT believes that the comment refers to Requirement R3 VSLs. The SDT agrees and has deleted the phrase ‘NERC registered’ from all VSLs for Requirement R3.

2) The SDT disagrees and believes that an incremental approach is the correct one for reliability. No change made.

3) The SDT agrees and has deleted the phrase ’whichever is less’ from the Severe VSL only for both Requirement R8 and R9.

4) The SDT disagrees but has made grammatical corrections to the VSLs which it believes may have led to confusion.

5) The SDT disagrees and believes that the wording is correct. No change made.

6) The SDT disagrees and believes that the wording is correct. No change made.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>Duke Energy does not necessarily disagree with the VRF(s) for IRO-017. However, we are seeking clarification for the increases in VRF from a “lower” in the first posting to a “medium” on this posting.</td></tr>
<tr><td>PacifiCorp</td><td>No</td><td>PacifiCorp cannot support the proposed change of the Violation Risk Factor in IRO-017-1 R3 from Low to Medium with inadequate justification for the change.</td></tr>
<tr><td colspan="3">Response: As was pointed out in the VRF/VSL Justification document for the second posting, the Medium VRFs are because of the need to correspond to similar requirement VRFs for consistency as per the VRF Guidelines. Similar requirements had Medium VRFs so proposed IRO-017-1 was assigned Medium VRFs.</td></tr>
</table>

Organization	Yes or No	Question 11 Comments
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	IRO-008-2R4 - Change the Severe VSL for new Requirement R4 (old R5) to read '...more than three...' or '...four or more...' in lieu of '...three or more...'. The High VSL already uses three. IRO-014-3R3 - The lead-in for the VSLs for Requirement R3 refers to Requirement R5. This reference should be to Requirement R3. R7 - Change the Severe VSL for Requirement R7 to read '...Coordinator had implemented...' and '...or would have violated safety...'. IRO-017-1R2 - Make Reliability Coordinator possessive in the Severe VSL for Requirement R2. TOP-001-3R8 - Delete 'other' in the VSLs for Requirement R8 referring to '...other known impacted Balancing Authorities...' and '...other Balancing Authorities...'. The use of 'other' only applies to references to Transmission Operator. Also in the VSLs for R8, change 'less' to 'greater' such that the Lower VSL would read: 'The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the affected known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.' (This particular change applies to all VSLs in R8, R9, R19 and R20 as well as the VSLs for IRO-002-4, R1; IRO-008-2, R3, R5, R6; IRO-010-2, R2; TOP-002-4, R3, R5; TOP-003-3, R3, R4.) R9 - Delete the term 'NERC registered' in the VSLs for Requirement R9. (See comment in Question 7 above. R13 - Change the Severe VSL for Requirement R13 to read '...more than three...' or '...four or more...' in lieu of '...three or more...'. The High VSL already uses three.

Organization	Yes or No	Question 11 Comments
		R19/R20 - Replace 'applicable' with 'identified' in the VSLs for Requirements R19 and R20. The use of 'identified' parallels the language in the requirements. TOP-002-4R3 - Replace 'NERC' with 'entities' in the High and Severe VSLs for Requirement R3.
Response: Proposed IRO-008-2 Requirement R4 VSL does not use the 'three or more' language cited. No change made. IRO-014-3 Requirement R3: The SDT agrees and has corrected the typo. IRO-014-3 Requirement R7: The SDT agrees and has made the suggested change. See summary for wording. IRO-017-1 Requirement R2: The SDT agrees and has made the suggested change. See summary for wording. TOP-001-3 Requirement R8: The SDT agrees and has deleted 'other' as suggested. See summary for wording of Severe VSL. TOP-001-3 Requirement R8: The SDT agrees with the change of 'lesser' to 'greater' in this standard and all others cited. Due to the simple replacement of one word and the volume of changes, the actual changes are only shown in the redlined standards. TOP-001-3 Requirement R9: The SDT agrees and has deleted the term 'NERC registered'. Due to the simple deletion of the phrase, the actual changes are only shown in the redlined standards. TOP-001-3 Requirement R13: The SDT agrees and has made the suggested change. See summary for wording. TOP-001-3 Requirement R19 and R20: The SDT agrees and has made the suggested change. Due to the simple replacement of one word, the actual changes are only shown in the redlined standards. TOP-002-4 Requirement R3: The SDT agrees and has made the suggested change. See summary for wording.		
Tennessee Valley Authority	No	TOP-001-3. There should be more than one level of VSL. As currently written there seems to be no allowance for instances where entities may be operating at two different ratings (i.e. temperature-dependent ratings, directional ratings, etc.) or a period of time before the entities coordinate which rating should be used in real-time.

Organization	Yes or No	Question 11 Comments
Response: The VSL for this requirement is based on a similar requirement and VSL for approved IRO-009-1 Requirement R5. That VSL is binary Severe. The SDT is supposed to structure VSLs whenever possible from existing approved VSLs. Therefore, the SDT assigned a binary Severe VSL to this requirement. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern disagrees that any violation of IRO-001-4 requirements constitutes a Severe VSL. The RSAW suggests that auditors are to use the NERC EAP process (i.e. reviewing entity's Category 2 or higher events) in their compliance assessment. Southern agrees with this approach and suggest the SDT adopt this thought process in the VSLs. For example, a Severe VSL would be a case where there was non-compliance for a Category 4 or 5 event, a High VSL would be for Category 3 events, and so on. This method should be used as not all events where Operating Instructions are issued, are equal.
Response: The VSLs for these requirements are based on similar requirements and VSLs for approved IRO-001-1.1. Those VSLs are binary Severe. The SDT is supposed to structure VSLs whenever possible from existing approved VSLs. Therefore, the SDT assigned a binary Severe VSL to these requirements. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	TOP-001-3 R2 Severe VSL - Remove "within its Transmission Operator Area" to maintain consistency with current R2. TOP-001-3 R7 Severe VSL - Replace "if requested" with "when requested" and "when the requesting" with "and the requested" to avoid issues with predicting future performance, and correct possession of the requested entity. Suggested language: "The Transmission Operator did not provide assistance to other Transmission Operators, when requested and able and the requested entity had implemented its emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements."

Organization	Yes or No	Question 11 Comments
Response: The SDT assumes that the commenter is referring to Requirement R1. The SDT has made changes to the requirement language which is reflected in the VSL language. See summary for wording. The SDT agrees and has made the suggested changes. See summary for wording.		
Hydro Quebec	No	TOP-001-3: Table of Compliance Elements: VSLs for R8 and R9 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. Example: "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted Transmission Operators or other known impacted Balancing Authorities that the Responsible Entity did not inform of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas or Balancing Authority Areas when conditions did permit such communications :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" The whole wording of the requirement could be omitted for more clarity :"Violation Severity Levels for requirement 8 are determined based on the number of other known impacted entities that the Responsible Entity did not inform in accordance with that requirement :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" IRO-008: Table of Compliance Elements: VSLs for R4, R6 and R8 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.

Organization	Yes or No	Question 11 Comments
		IRO-010: Table of Compliance Elements: VSLs for R2 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.
Response: The language cited by the commenter as an 'introduction' to the Requirement R8 and R9 VSLs has been used previously in other standards and is an acceptable method. The SDT has made changes to the language of the VSLs based on other comments but believes that the remaining language is clear as written. The re-worded Severe VSLs are shown in the summary. There is no Requirement R8 for proposed IRO-008-2. The SDT has made changes to the language of the VSLs in proposed IRO-008-2 based on other comments but believes that the remaining language is clear as written. See the redlined standard for the complete list of changes. The language cited by the commenter as an 'introduction' to the Requirement R2 VSLs has been used previously in other standards and is an acceptable method. The SDT has made changes to the language of the VSLs based on other comments but believes that the remaining language is clear as written. See the redlined standard for a complete list of changes.		
ERCOT	No	IRO-008: ERCOT suggests that the SDT review the language of Requirement R5 and its VSL for consistency. In particular, Requirement R5 was modified to require that the Reliability Coordinator ensure that a Real-Time Assessment is performed every 30 minutes. However, the VSL still assesses the condition that the Reliability Coordinator did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. These should be reviewed and revised to ensure consistency between the requirement and its VSL. IRO-008: ERCOT has identified a potential typographical error in R6 and all of its VSLs. Specifically, the reference to "as identified in identified in Requirement R6" should likely be reviewed and revised to "as identified in Requirement R5". IRO-008: ERCOT respectfully reiterates its previous comment on the inconsistent language used between Requirements R5 and R6 and the LOWER VSL for Requirement R8. In particular, the word "Emergency" is used in the VSL for Requirement R8 but the condition is not specified elsewhere in the standard or the appropriate referenced requirements. Please revise the lower VSL for

Organization	Yes or No	Question 11 Comments
		Requirement R8 to ensure consistency. The following language is proposed: "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated". IRO-014: ERCOT respectfully recommends that, for consistency, the VSLs for Requirement R2 be modified to remove references to criteria and state that Reliability Coordinator failed to maintain Operating Plans, Processes, or Procedures pursuant to one part of Parts 2.1 - 2.3, two parts of Parts 2.1 - 2.3, and so on.
Response: The SDT assumes the commenter is referring to Requirement R4 and agrees and has made changes to the Severe VSL. See summary for wording. The SDT agrees and has corrected the typographical error. The SDT assumes the commenter was referring to Requirement R6 Lower VSL as there is no Requirement R8. The SDT agrees and has corrected the typographical error. The SDT agrees and has made the suggested changes. See summary for wording.		
IRC Standards Review Committee Independent Electricity System Operator	No	IRO-008: R6 and all of its VSL: The reference to "as identified in identified in Requirement R6" should be revised to "as identified in identified in Requirement R5". IRO-008: We wish to reiterate our previous comment on the inconsistent language used between Requirement R6 (was R8 but misquoted in our previous comment as R6) and the LOWER VSL for R6 in which the word "Emergency" is used but the condition is not specified in R6.R6 stipulates that: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. However, the LOWER VSL for R6 indicates that: The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan "when the Emergency

Organization	Yes or No	Question 11 Comments
		identified in Requirement R6 was prevented or mitigated." Please revise VSL to read "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated" as opposed to "Emergency" for consistency. IRO-008: The language between R4 and its VSL is inconsistent.R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC to "perform" to "ensure that" a Real-time Assessment is performed. However, the VSL still assesses the condition that the RC did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. Please revise as appropriate.
Response: The SDT agrees and has corrected the typographical error. The SDT agrees and has corrected the typographical error. The SDT agrees and has changed the VSL language. See summary for wording.		
Peak Reliability	Yes	TOP-001-3 R13: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted ...3 times....Severe VSL TO RTA not conducted 3 or more times...) IRO-008-2 R4: The VSL removed the first occurrence of the term "NERC registered" entity but left the term in the second half of the VSL. IRO-008-2 R5: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted ...3 times....Severe VSL TO RTA not conducted 3 or more times...)
Response: The SDT agrees and has revised the Severe VSL. See summary for wording. The SDT assumes that the commenter is referring to Requirement R3 and agrees and has made the suggested change. See summary for wording. The SDT assumes the commenter is referring to Requirement R4 and agrees and has made the suggested change. See summary for wording.		

Organization	Yes or No	Question 11 Comments
Northeast Power Coordinating Council Hydro One	Yes	
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Yes or No	Question 11 Comments
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
ReliabilityFirst	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
MidAmerican Energy Company	Yes	
Response: Thank you for your support.		

12. **Are there any other concerns with these standards that haven't been covered in previous questions and comments?**

Summary Consideration: The SDT has not made any additional changes to the standards based on comments to this question.

Organization	Yes or No	Question 12 Comments
Dominion Compliance Policy	Yes	Dominion encourages the SDT to continue to monitor the status of the proposed definition of Remedial Action Scheme "RAS" as the change in definition will impact this reliability standard as well as other related standards as identified in NERC's white paper, Uses of "Special Protection System" and "Remedial Action Scheme" in Reliability Standards.
Response: Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term then a project will be undertaken to make the necessary corrections throughout all standards. No change made.		
Texas Reliability Entity	Yes	1) Texas RE appreciates the work that the SDT has done to address the comments received from industry during the previous ballot and comment period. Thank you for the time you have put into working towards making a set of steady state TOP and IRO standards. 2) Texas RE has one general comment regarding data retention for all the standards within this project. Texas RE recommends the SDT consider aligning the retention periods with the Data Retention and Sampling Team (DRAST) white paper which indicates a 4-year retention period for data with limited exemptions, such as a 6-month rolling period for high volume data, and 90-days for voice and audio recordings. 3) Operational Planning Analysis definition: Texas RE requests the SDT provide explanation for why the phrase "may be performed either a day ahead or as much as 12 months ahead" was removed from the proposed definition. The phrase is included in the current Glossary defined term. Following up on our comment from the

Organization	Yes or No	Question 12 Comments
		previous ballot and comment period, Texas RE still asserts that without that phrase the time frame for one day up to 12 months is not accounted for.
Response: Thank you for your support. The SDT has reviewed the data retention periods and believes that they are correct as stated. No change made. The SDT believed the parenthetical was not required as part of the definition. The Operations Planning Time Horizon includes conditions seen in studies, from day-ahead up to and including seasonal (which the SDT has stated that it believes essentially equates to one year), that may impact the Real-time reliability of the Reliability Coordinator Area. No change made.		
FRCC Compliance	Yes	1. IRO-001-4 R1, TOP-001-3 R1 & R3: The phrase "... to ensure the reliability of its RC/TOP/BA Area." is not measurable. The requirements should be stated so that the stated reliability is objectively measurable. For example, "... to ensure all Facilities within the RC/TOP/BA Area remain within SOLs and IROLs." Otherwise, the requirements are too vague as to when the RC/TOP/BA would be required to act, or whether the action taken was sufficient to ensure reliability. 2. TOP-002-4 R1: The definition of Operational Planning Analysis does not specify what "potential (post-Contingency) conditions" are to be evaluated, and is therefore not measurable. Either the requirement or the definition should be revised to clarify and add measurability as to which contingencies are required to be included in the analysis. 3. TOP-002-4 R4 (4.2): The phrase "...for the next-day that addresses: Interchange scheduling" is too vague and not measurable. The requirement should be stated so as to be objectively measurable. For example, "... for the next-day that addresses: Expected Interchange scheduling". 4. TOP-002-4 R4 (4.4): The phrase "... for the next-day that addresses: Capacity and energy reserve requirements ..." is not measurable. Applicable reserve requirements should be clearly provided to provide measurability as to whether the Operating Plan

Organization	Yes or No	Question 12 Comments
		addressed them. For example, "... for the next-day that addresses: Capacity and energy reserve requirements (at a minimum N-1 Contingency planning) ..."

Response: 1. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting.

2. The purpose of proposed TOP-002-4 Requirement R1 is to perform an Operational Planning Analysis to identify SOL exceedances. The SOL Exceedance White Paper provide additional clarity by pointing to other requirements within FAC, TOP and IRO standards, including examples. No change made.
3. The SDT believes "expected" is implied since the Operational Planning Analysis is targeting "next-day" system conditions. No change made.
4. The SDT chose to use the generic term "Capacity and Energy Reserve Requirements" as part of the Interconnection-wide standard and believes that it is measurable. Minimum Reserve Requirements are addressed as part of the BAL standard. Balancing Authorities may have differing reserve requirements based on system conditions that need to be communicated to their Transmission Operator and Reliability Coordinator. No change required.

Organization	Yes or No	Question 12 Comments
Puget Sound Energy	Yes	As discussed in the comments addressing IRO-017, requirements R1 and R2 of that proposed standard should be phased with requirement R1 becoming effective prior to R2. Just as in IRO-010, the BAs and TOPs subject to requirement R2 are likely to need some time to implement the processes specified in RC's outage coordination process. In addition, connecting the implementation time to COM-001-2 if this group of standards is approved prior to or concurrent with COM-001-2 and COM-002-4 could result in a short implementation time. For example, say that FERC approval of both the COM standards and the IRO/TOP standards becomes effective on June 30, 2015. According to the implementation plan, the standards will "become effective concurrently with COM-001-2 and the definition of Operating Instruction". The effective date of COM-001-2 is "first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities..." which would be October 1, 2015 in this example. There is some ambiguity with this result since the term Operating Instruction is not used in COM-001-2, but in any case, using the effective date of COM-002-4, which is more consistent with the implementation period of the IRO/TOP standards, seems more appropriate.

Organization	Yes or No	Question 12 Comments
Response: The SDT disagrees that a staggered approach is needed. These items are not going to be created in a vacuum and the SDT believes that the entities involved will be coordinating as the process is developed. No change made.		
Northeast Power Coordinating Council	Yes	Because of the similarities in Purposes, Applicability's, and Requirements of standards within the group that is posted, combining requirements with the intent on reducing the number of standards should be considered. During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid. In other word, there does not exist any "proven reliable power system limits" as stated in R4 of TOP-002-4. While the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon may seem appropriate, the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state. If R4 in TOP-004-2 is retired, it leaves a potential reliability gap. The white paper does not mandate the proper and necessary action to "restore operations to respect proven reliable power system limits within

Organization	Yes or No	Question 12 Comments
		30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. A proper Quality Review of the postings would have eliminated the necessity of submitting many of the above comments.
Response: The SDT has made every effort to consolidate topics to reduce the number of requirements and standards in this project. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_v. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. The SDT submitted the documents to Quality Review as required and received numerous comments and suggestions for changes/corrections that were accepted by the SDT.		
IRC Standards Review Committee Independent Electricity System Operator	Yes	During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. he SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing

Organization	Yes or No	Question 12 Comments
		and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any "proven reliable power system limits" as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary action to "restore operations to respect proven reliable power system limits within 30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. Please advise.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 12 Comments</th></tr>
<tr><td colspan="3">Response: 1. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_v. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made.
2. The SDT does not plan on balloting for the retirement of approved TOP-004-2 since the intent of the requirement was successfully mapped as part of the Mapping Document. Acceptance of the proposed standards which includes the Mapping Document is considered sufficient to retire the standards cited in the Implementation Plan. No change made.</td></tr>
<tr><td>Northern Indiana Public Service Company (NIPSCO)</td><td>Yes</td><td>NIPSCO is voting against approving the definitions for the following reasons: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. See our comments on TOP-002 for more information.
2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?</td></tr>
<tr><td colspan="3">Response: 1. The SDT recognizes the concern but believes the proposed TOP-001-3 Requirement R13, TOP-001-3 Requirement R14, TOP-002-4 Requirement R1 and TOP-002-4 Requirement R2 further define the purpose of the Real-time Assessment and Operational Planning Analysis is to address potential SOL exceedances. No change made.</td></tr>
</table>

Organization	Yes or No	Question 12 Comments
2. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term ‘applicable’ was intended to capture that intent and to protect an entity against unreasonable expectations. No change made.		
Seattle City Light	Yes	SCL asks that the Implementation Plan be revised to conform with our recommendations that the implementation periods and effective dates for IRO-010-2 and TOP-003-3 be extended to eighteen and twenty-four months (to allow sufficient time to negotiate and implement data exchange agreements among entities), as indicated above.
Response: The SDT does not believe that additional implementation time is required. Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	Yes	The definition of Special Protection System (SPS) is being revised to Remedial Action Scheme (RAS) yet this package of standards continues to use SPS. Other active drafting teams, particularly the Relay Loadability: Stable Power Swings and the Protective System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) teams, are using the new RAS definition in their work. What process will be used to make the transition to RAS when the new definition is approved? Similarly, Load-Serving Entity will soon be eliminated as a registered function at NERC. How will this change be reflected in the standards? We recommend that all changes we have proposed for the standards be reflected in the RSAWs as well.

Organization	Yes or No	Question 12 Comments
Response: Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term then a project will be undertaken to make the necessary corrections throughout all standards. No change made. Changes to requirement language due to industry comments will be reflected in RSAWs.		
Electric Reliability Council of Texas, Inc.	Yes	1. The proposed definitions of Real-Time Assessment and Operational Planning Analysis require use of applicable inputs. ERCOT respectfully submits that many of these inputs can only be utilized once communicated by other entities. Accordingly, the following revision is proposed: Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable, known inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted third-party services.) Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable, known inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted third-party services.) 2. During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that:R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30

Organization	Yes or No	Question 12 Comments
		minutes. The SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any "proven reliable power system limits" as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary

Organization	Yes or No	Question 12 Comments
		action to "restore operations to respect proven reliable power system limits within 30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. 3. TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.

Response: 1. The SDT recognizes that only known inputs can be included as part of an RTA or OPA once the required information is communicated by other entities. No change made.

2. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_V. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these

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functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. 3. The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. The mapping document has been updated accordingly. 4. The SDT disagrees and believes that the proposed replacement addresses the situation. No change made. 5. Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. The SDT updated the mapping document.		
PacifiCorp	No	TOP-001-3 exceeds the NOPR by requiring Protection Systems in addition to Special Protection Systems. The tools used to produce Real-time Assessments using Real-time data are not dynamic stability assessment tools, and do not inherently understand the status of all "Protection Systems", degradations, or identified phase angles and equipment limitations. Note the definition references "Protection System and Special Protection System status," while the NOPR references only Special Protection Schemes.
Response: The SDT was required to consider additional inputs beyond the FERC NOPR as part of the Standards Development process. The SDT recognizes that not all Real-time Assessment tools include dynamic Stability assessments. Typically facilities with degraded protection systems are switched out-of-service. If the facilities are not switched out-of-service, Contingencies within the		

Organization	Yes or No	Question 12 Comments
Real-time Assessment should be modified to reflect remote clearing. If there are transient Stability concerns, Operating Plans would address expected operator actions. No change made.		
FRCC Operating Committee (Member Services) City of Tallahassee	Yes	The comments provided herein are consensus comments of the FRCC Operating Committee entity representatives. Our responses to the above questions in no way intends to convey how individual FRCC OC member entities will vote on the standards being proposed. Thank you for your efforts.
Florida Municipal Power Agency	No	FMPA appreciates the good work of the SDT in streamlining and improving the clarity of these standards.
PJM Interconnection	No	PJM is submitting affirmative ballots for all the standards. The revisions made to IRO-002-4 and IRO-008-2 addressed PJM's concerns with the previous drafts of these standards.
Associated Electric Cooperative, Inc. - JRO00088	No	
MRO NERC Standards Review Forum	No	
ACES Standards Collaborators	No	
Duke Energy	No	
Bonneville Power Administration	No	
Arizona Public Service Company	No	

Organization	Yes or No	Question 12 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Peak Reliability	No	
Clark Public Utilities	No	
American Electric Power	No	
South Carolina Electric and Gas	No	
CenterPoint Energy Houston Electric LLC	No	
Manitoba Hydro	No	
Pepco Holdings Inc.	No	
Idaho Power Company	No	
American Transmission Company, LLC	No	

Organization	Yes or No	Question 12 Comments
Xcel Energy	No	
Salt River Project	No	
Consumers Energy Company	No	
Oncor Electric Delivery LLC	No	
ReliabilityFirst	No	
Tennessee Valley Authority	No	
New York Independent System Operator (NYISO)	No	
Ameren	No	
Tri-State Generation and Transmission Association, Inc.	No	
Hydro One	No	
Northeast Utilities	No	
Georgia Transmission Corporation	No	
CPS Energy	No	
Indiana Municipal Power Agency	No	

Organization	Yes or No	Question 12 Comments
MidAmerican Energy Company	No	
Response: Thank you for your support.		

END OF REPORT