Consideration of Comments

Project 2009-03 Emergency Operations

The Project 2009-03 Emergency Operations (EOP) standard drafting team (SDT) thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from September 5, 2014 through October 20, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 36 sets of comments, including comments from approximately 131 different people from approximately 88 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. The SDT has given every comment serious consideration in this process. However, 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

1. EOP-011-1. Do you agree with the changes made to EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue 11
2. Attachment 1. Do you agree with the changes made to Attachment 1 of EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue 37
3. Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The EOP SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for EOP-011-1? If you do not agree, please explain why and provide recommended changes 55
4. Are there any other concerns with the proposed standard that have not been covered by previous questions and comments? If so, please provide your feedback to the EOP SDT 61

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	Janet Smith	Arizona Public Service Company	X		X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

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

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Brian Robinson	Utility Services	NPCC	8
18.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
19.	Helen Lainis	Independent Electricity System Operator	NPCC	2
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New Yor Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
2.	Mike Garton	NERC Compliance Policy	NPCC	5
3.	Randi Heise	NERC Compliance Policy	RFC	5, 6

4.	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

5.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	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.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Hoag	FirstEnergycorp	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dressner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FitstEnergy Solutions	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company;	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy,LLC	SERC	3
2.	Anette Bannon	PPL Generation, LLC	RFC	5
3.		PPL Susquehanna, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			SPP	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Phil Hart	Associated Electric Cooperative, Inc.	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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5

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

2.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Brandon Levander	Nebraska Public Power District	MRO	1, 3, 5
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3, 5
10.	Jason Smith	Southwest Power Pool	SPP	2
11.	John Stephens	City Utilities of Springfield	SPP	1, 4
12.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
13.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4
14.	Bryn Wilson	Oklahoma Gas & Electric	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	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.	Dale Goodwine			5
4.	Greg Cecil			6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
2.	Ginger Mercier	Prairie Power, Inc.	SERC	3
3.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

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

4. Amber Skillern	East Kentucky Power Cooperative	SERC	1, 3, 5
5. John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
6. Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
7. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
8. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Jared Shakespeare	Peak Reliability	X									

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee (SRC)		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Matt Goldberg	ISO-NE	NPCC	2
2. Christina Bigelow	ERCOT	ERCOT	2
3. Cheryl Moseley	ERCOT	ERCOT	2
4. Terry Bilke	MISO	MRO	2
5. Al DiCaprio	PJM	RFC	2
6. Charles Yeung	SPP	SPP	2
7. Ali Merimadi	CAISO	WECC	2
8. Ben Li	IESO	NPCC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Technical Operations	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Individual	Leonard Kula	Independent Electricity System Operator		X								
19.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
20.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
21.	Individual	Denise M Lietz	Puget Sound Energy	X		X		X					
22.	Individual	Joe O'Brien on behalf of David Austin	NIPSCO	X		X		X	X				
23.	Individual	Dave Willis	Idaho Power	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Anthony Jablonski	ReliabilityFirst										X
25.	Individual	John Merrell	Tacoma Power	X		X	X	X	X				
26.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
27.	Individual	Matthew Beilfuss	We Energies			X	X	X					
28.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
29.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
30.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
31.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
32.	Individual	Catherine Wesley	PJM Interconnection		X								
33.	Individual	Matthew F. Goldberg	ISO New England Inc.		X								
34.	Individual	Gregory Campoli	New York Independent System Operator		X								
35.	Individual	Karin Schweitzer	Texas Reliability Entity										X
36.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: None required for this section.

Organization	Agree	Supporting Comments of "Entity Name"
N/A	N/A	N/A

1. EOP-011-1. Do you agree with the changes made to EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue

Summary Consideration: The EOP SDT appreciates all of the comments received.

Puget Sound Energy provided a comment requesting the EOP SDT to consider revision of the NERC glossary defined term “Emergency.” The EOP SDT appreciates the suggestion; however, the drafting team has determined that the language is appropriate as drafted. The use of the NERC defined glossary term “Emergency” provides clarity regarding the types of events and situations to be included in the Operating Plan(s).

Duke Energy provided a revision suggestion to the revised defined term Energy Emergency to include “…or balancing obligations respectively.” Energy Emergency results from an inability to serve Load; it is not necessarily dependent upon balancing issues, therefore, the drafting team elected to retain the language as drafted.

A number of stakeholders commented about multiple plans. It was the EOP SDT’s intent in Requirements R1 and R2 that the Operating Plan(s) could be one plan or multiple plans, as stated in the Rationale boxes for these requirements; but agrees with Tennessee Valley Authority that consistency is needed and has made the clarifying revision “Plan(s)” throughout the standard. In addition, ACES Standards Collaborators requested clarification regarding entities that serve as both a Balancing Authority and Transmission Operator, if a single Operating Plan is acceptable under the drafted Requirements R1 and R2. It is the intent of the EOP SDT that if an entity is both a Balancing Authority and a Transmission Operator, they can have a single Operating Plan to address both the Balancing Authority and Transmission Operator aspects of addressing an Emergency. If an entity is both a Balancing Authority and Transmission Operator and prefer to have separate Operating Plans, that is acceptable as well; it is the intent of the EOP SDT for this determination to be made by the entity.

For Requirement R1, Texas Reliability Entity submitted a comment for clarification of entity functions that are considered part of a Transmission Operator Area. The intent of the drafting team is that a specific generator may not be included in a Transmission Operator Area, but a specific generator must be within the metered boundaries of a Balancing Authority Area. Some Transmission Operators cancel or recall transmission and generation outages and some Transmission Operators do not. The Operating Plan(s) should address the entity’s specific situation.

SPP offered revised language revisions to Requirement R1 Part 1.2.5. The EOP SDT appreciates the comment, but will retain the existing language of Requirement R1 Part 1.2.5.; the drafting team believes it provides the necessary focus. Duke Energy commented as well to Requirement R1 Part 1.2.5., stating their understanding of the language “capable of being implemented in a timeframe adequate for mitigating the Emergency” in the requirement part as: “It is our understanding that this phrase provides an entity the flexibility to identify on its own, the timeframes it deems adequate for mitigating emergencies within their Operating Plan." The EOP SDT thanks you for your comment and confirms that your interpretation of Requirement R1 Part 1.2.5. is correct.

American Electric Power submitted the following comment regarding Requirement R1 Parts 1.2.2. and 1.2.4.: "…AEP does not believe it is within the TOP's jurisdiction to perform such actions within their Transmission Operator Plan. Rather, AEP believes it would be the BA's responsibility to recall generation outages or redispatch generation." The EOP SDT recognizes that it may be necessary for both the Balancing Authority and Transmission Operator to notify the GOP for Emergency conditions, which can be both Capacity/Energy or Transmission related. Therefore, the EOP SDT has retained the language as drafted. TLR or market-based congestion management processes do not apply throughout North America.

The EOP SDT retained the requirement language to include "provisions" in Requirement R1 Part 1.2.5 and Requirement R2 Part 2.3.7 due to a number of stakeholder comments on the previous posting. WE Energies and SPP requested clarification and language revision suggestions of Requirement R2 Part 2.2.8. The EOP SDT's intent in Requirement R2 Part 2.2.8. is that this related to "provisions for operator-controlled manual Load shedding…" This allows for the Operating Plan(s) regardless of whether the entity is a vertically integrated utility or not. The EOP SDT believes the existing language provides the necessary intent.

In response to comments received from Duke Energy, ACES Standards Collaborators, American Electric Power, ReliabilityFirst, WE Energies, and Tri-State Generation and Transmission Association, Inc., the EOP SDT believes it is important to minimize the overlap with automatic Load shedding and will retain the language as drafted. In addition, the drafting team will propose language revisions to the RSAW to include a review of the process aspect of Load shedding rather than the actual amount of Load that might be shed during an Emergency.

NIPSCO requested clarification of the justification of Long-term Planning horizons for Requirements R1 and R2. In some cases, an entity may have planning horizon studies which require Operating Plan(s) to be developed to mitigate or address them. The language of Requirements R1 and R2 says the plans are to be developed, maintained, and implemented. In addition, NIPSCO requested clarification on the distinction between TOP-002-4/TOP-001-3 and EOP-011-1 Operating Plans. In response, the EOP SDT would like to make this clarification by stating that TOP-002-4/TOP-001-3 are not the same operating plans, as those plans deal with addressing SOLs, while EOP addresses Emergencies.

Additional clarification was requested for Requirement R2 Part 2.2.3. The EOP SDT maintains that Requirement R2 Part 2.2.3, as drafted, provides the necessary details and clarity regarding generating resources.

EOP SDT drafted Requirements R1 and R2 to correlate with the general industry consensus regarding the intent of "extreme weather conditions." The EOP SDT would like to thank PPL NERC Registered Affiliates for their comments; however, each item of the requirement parts in Requirements R1 and R2 need to be addressed, and state where they are not applicable, in the Operating Plan(s), the language as drafted was retained.

DTE Electric, ACES Standards Collaborators, SRC, American Electric Power, ReliabilityFirst, WE Energies, and Tri-State Generation and Transmission Association, Inc. submitted comments requesting clarification, as well as suggesting revisions of Requirement R3 and Requirement R3 Parts 3.1. and 3.1.3. The drafting team has revised Requirement R3 and Requirement R3 Parts 3.1. and 3.1.3 to provide clarification and notification specificity, as follows:

"R3. The Reliability Coordinator shall~~, within 30 calendar days of receipt,~~ review each Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. Within 30 calendar days of receipt, ~~The~~ the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified."

The EOP SDT augmented Requirement R3 Part 3.1.3. to provide clarity to the required actions of the Reliability Coordinator. Specifically, the SDT added language to ensure that the Reliability Coordinator specifies a time frame for resubmittal of the Operating Plan(s) as needed. The intent of the SDT, reinforced by the language of other requirements, does not change with inclusion of this language, as Requirement R4 anticipates a time period will have been specified by the Reliability Coordinator upon the discovery of a reliability risk. Thus, this change is consistent with the scope, applicability, and intent of the previous draft of EOP-011-1.

Duke Energy provided a suggestion to combine Requirement R3 and Requirement R4. Requirement R3 and Requirement R4 were written with the EOP SDT's intent to not be prescriptive, while still providing the reliability requirements necessary. The EOP SDT maintains that, rather than combining the requirements, they should remain separate.

Several commenters requested clarification regarding the coordination of Operating Plan(s) under Requirement R3. When reviewing the Operating Plan(s), the RC is looking for deficiencies, inconsistencies, or conflicts between the submitted plans that would cause further degradation to BES during Emergency conditions.

The EOP SDT notes that a Capacity or Energy Emergency is a subset of an operating Emergency and has retained the term "operating Emergencies" in Requirement R3.

Manitoba Hydro provided language revision suggestions for Requirement R4 to include the language: “make a good faith attempt to address.” The EOP SDT believes that the coordination should resolve any reliability risks identified during the review. The RC has the authority to require a TOP or BA to take actions in cases of Emergency.

To address the comments received by SPP, NIPSCO, WE Energies and Salt River Project regarding maintenance of Operating Plan(s) in EOP-011-1, the EOP SDT drafted the standard to allow flexibility to the Transmission Operator and Balancing Authority with regards to frequency of maintenance on their plan(s). The intent is to ensure that their plan(s) are maintained so that they are available for implementation to address an Emergency. The Measure also includes language regarding maintenance: “… evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained.”

The EOP SDT received comments requesting a clarification of periodic reviews on Operating Plan(s) to mitigate Emergencies. The EOP SDT does not believe that there needs to be a periodic review on the Operating Plan(s) and declines to include this requirement in the standard.

Comments were received from Associated Electric Cooperative, Inc. and ReliabilityFirst requesting clarification of the EOP SDT’s intent in the use of the term “implement.” An Operating Plan is implemented by carrying out its stated actions, which the drafting team intended to be used consistently with the use of this term in similar standards.

In response to comments received, the EOP SDT has revised Attachment 1 to replace “adjacent” with “neighboring.”

SPP and MRO NERC Standards Forum requested the language “impacted” be re-inserted into the draft standard to provide clarity. The EOP SDT retained “neighboring” and has removed “impacted” to ensure notifications for situational awareness. The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators.

Duke Energy provided the suggested language revision to Requirement R5: ”Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority, as identified in its respective Operating Plan shall notify, within 30 minutes from the time of receiving notification, affected Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and affected neighboring Reliability Coordinators.” The EOP SDT believes the suggested changes assume that the Reliability Coordinator has an Operating Plan, this is not necessarily an accurate assumption. The suggested revision was not made.

The EOP SDT notes that Requirement R5 requires notifications to Transmission Operators, Balancing Authorities and neighboring Reliability Coordinators. IRO-014-3 limits the notification to “other impacted” RC’s. The EOP SDT believes, in Requirement R5, that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Requirement R6, as SPP correctly commented on, is a holdover from EOP-002-3.1, Requirement R8. The rationale box for Requirement R6 is incorrect and has been removed.

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	No	Standard requirements should reflect Operating Plan(s), not Operating Plan. Rationale states that there can be multiple plans. Recommend uses “Plan(s)” in place of “Plan” consistently through the Standard. R2.2.3.1 and subrequirements and R2.2.9. need more clarification. Webinar discussion implied the Balancing Authority needed to have awareness of generator availability and constraints. Recommend changing R.2.2.3 to remove “Managing generating resources “ and use “Maintain awareness of generator capability and availability” and delete “to address” and the subrequirements. Recommend changing R2.2.9 by inserting “Maintain awareness of” at beginning of requirement. R3.1.1. should be clarified by inserting “within its Reliability Coordinator Area” at the end of the requirement. R3.1.3 should be clarified by inserting “submitting” after “Notify each”.
FirstEnergycorp	No	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that:3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; andWe are not clear on what it means by “Review each submitted Operating Plan for coordination”. Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting

Organization	Yes or No	Question 1 Comment
		entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.The PPL NERC Registered Affiliates support the revisions that have occurred between draft 2 and this draft 3 of Attachment A. However, additional improvements and clarification could be made. The term “extreme weather conditions” used in R1 Part 1.2.6 and R2 Part 2.2.9, is subjective. Auditors and entities may consider different types of weather “extreme.” Further description or guidance is needed to enable compliance. In addition, unlike R1 Parts 1.2.1 thru 1.2.5 and R2 Parts 2.2.1 thru 2.2.8, it is not clear how “Reliability impacts of extreme weather conditions” is a process (in part because there is no verb before reliability). If it is the SDT’s intention that Operating Plans to mitigate Emergencies include preparations for extreme weather conditions, PPL Companies recommend the following changes be made to R1 and R2: - R1 Part 1.2.6 should be moved above Part 1.2 and read, “Preparation for the reliability impacts of extreme weather conditions;” - R2 Part 2.2.9 should be moved above R2 Part 2.2 and read, “Preparation for the reliability impacts of extreme weather conditions.” Accordingly, the numbering of Parts 1.2 and 2.2 as they appear in draft 3 would become 1.3 and 2.3.
Associated Electric Cooperative, Inc.	No	AECI agrees with SPP Comments
SPP Standards Review Group	No	R1/R2 - While we have seen the ‘develop, maintain and implement’ language in other standards, we continue to be a bit unsure just how we

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		are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.'Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace '...how you will make a notification to the...' with '...when the Transmission Operator must notify its...'.R2-Insert 'within its Balancing Authority Area' at the end of the 1st sentence of the requirement.R2.2.1- Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to

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		replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.'Rational for Requirement R2 - Delete 'Emergency' in 'Emergency Operating Plan' in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase 'as much as possible' off with commas as was done in the Rationale for Requirement R1.R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: '...shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority...'. Also, hyphenate '30-calendar days'.R3.1.1 - Add 'within its Reliability Coordinator Area' at the end of the Subpart.R3.1.2 - Modify the Subpart to the following: 'Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and'R3.1.3 - Add 'of its review' at the end of the Subpart.Rationale for R3 - In the 3rd line, change 'require' to 'requires'. Capitalize 'Emergencies' in the last line.M3 - Hyphenate '30-calendar days'.M4 - Replace 'emails' in the 2nd line with 'e-mails' to make it consistent with the usage in M3.R5/M5 - Insert the phrase 'within its Reliability Coordinator Area' after 'Balancing Authority' in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. 'Neighboring' is used in conjunction with Reliability Coordinator at the end of this requirement. 'Adjacent' is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term 'impacted' has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked

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		about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There's a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term 'impacted'. Modify Measure M5 to be consistent with the suggested changes to Requirement R5.The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. 'Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.' Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn't this requirement really a holdover from EOP-002-3.1, R8?
DTE Electric	No	Comments: The language in R3 requires the RC to review plans within 30 days but does not specify a time limit to notify the BA or TOP. R3 also does

Organization	Yes or No	Question 1 Comment
		not require the RC to specify a time period to the BA or TOP to address issues but R4 requires those issues to be addressed in a specified time frame. Suggested new language for R3:R3. The Reliability Coordinator, within 30 calendar days of receipt, shall review each Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. 3.1. The Reliability Coordinator review shall consist of the following actions: 3.1.1. Review each submitted Operating Plan on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans; 3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; 3.1.3. Notify each Balancing Authority and Transmission Operator of the results; and3.1.4. If risks are identified, specify a time frame for the affected Balancing Authority or Transmission Operator to address the risks and resubmit its plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Duke Energy	No	(1) Duke Energy suggests the following revision to requirement 1.2.5:"1.2.5. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and..."We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to "minimize the overlap with automatic Load shedding" which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement.(2) Could the SDT please clarify our understanding of the phrase "capable of being implemented in a timeframe adequate for mitigating the Emergency..." within requirement 1.2.5? It is our understanding that this phrase provides an entity the flexibility to identify on its own, the timeframes it deems adequate for mitigating emergencies within their Operating Plan. Is this

Organization	Yes or No	Question 1 Comment
		correct?(3) Duke Energy suggests the following revision to the definition of Energy Emergency:”Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load or balancing obligations respectively.”Per the NERC Functional Model, the LSE has the obligation to serve load and the BA has the obligation to maintain balance. We believe the addition of “Load or balancing obligations respectively” more accurately distinguishes the separate responsibilities of a LSE or BA during an Energy Emergency. .(4) Duke Energy suggests the following revision to requirement 2.2.8:”2.2.8. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and...”We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to “minimize the overlap with automatic Load shedding” which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement.(5) Duke energy suggests combining Requirements 3 and 4 as follows:”Each RC and Balancing Authorities and Transmission Operators within its RC Area shall review and revise the BA and TOP Operating Plans as necessary for coordination.” We believe the proposed R3 and R4 are too prescriptive in nature and may not address the intent of the SDT of promoting coordination of the Operating Plans among the listed functions. We feel that our suggested language captures more clearly the desired coordination as intended by the SDT.(6) Duke Energy suggests the following revision to requirement 5:”Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority, as identified in its respective Operating Plan shall notify, within 30 minutes from the time of receiving notification, affected Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and affected

Organization	Yes or No	Question 1 Comment
		neighboring Reliability Coordinators."We believe the NERC definition of Emergency is too broad within the context of this requirement. Per the NERC definition of Emergency, any tripping of generation or transmission line that "requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" would be subject to notification. This would be extremely burdensome for the RC(s), BA(s), and TOP(s). We believe the intent is for the RC to notify affected parties during an event that would put the reliability of the BES at risk. We believe our suggested language narrows the scope to only those events that have that very impact. We also believe that this was the intent of the SDT and not to require that every action taken by a BA/TOP prompt notifications to all BA(s) and TOP(s) within its RC area as well as neighboring RC(s). (7) We ask the EOP SDT to distinguish the differences between EOP-011-1 R5 and IRO-014-3 R3. As written, we believe the 2 requirements listed are similar and would create double jeopardy.
ACES Standards Collaborators	No	(1) We thank the drafting team for modifying Requirement R1 by requiring an Operating Plan rather than an Emergency Operating Plan. (2) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes.(3) For Requirement R3, Part 3.1.3, is there a time frame in which the RC must notify each BA and TOP? Requirement R3 states that the RC must review the Operating Plan within 30 calendar days of receipt, but there is no deadline to provide notice to the submitting entity.(4) For Requirement R4, there are concerns with the timeframes to update and resubmit modified Operating Plans. The requirement should include 30 calendar days of receipt, unless the RC mandates the change to be made sooner. Without any specific timeline, this requirement is difficult to measure what a reasonable time frame would be.(5) We disagree with

Organization	Yes or No	Question 1 Comment
		using the term “minimizes” in Parts 1.2.5 and 2.2.8. This implies that an optimal solution is required. While we agree it does makes sense to be thoughtful in the selection of loads for manual load shed, it simply may not be possible to avoid shedding loads that can also be shed via UFLS in many cases. For instance, there could be many critical loads (i.e. fire and police stations, army bases, hospitals) that prevent this and the system operator should not be burdened in a real-time Emergency with this “minimization” issue when they should be focused on mitigating the Emergency. Also, transmission Emergencies may require loads in a load pocket that has many UFLS relays to be shed. We suggest that Parts 1.2.5 and 2.2.8 be struck in their entirety and to cover this concept in the guidelines sections. The last paragraph in the rationale box for R1 and second to last paragraph for the rationale box for R2 both that the goal is to “minimize as much as possible.” This is inconsistent with the language of the requirement which requirements minimization. (6) Requirement R3 is inconsistent with Requirement R2. The requirement compels the RC to review Operating Plans “to mitigate operating Emergencies.” R1 uses the term operating Emergencies. R2 does not but rather uses Capacity and Energy Emergencies. R3 should be made consistent with the language in R2.
Peak Reliability	No	R5 should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies - just those that need to know such information.
ISO/RTO Council Standards Review Committee (SRC)	No	1. The SRC believes that Requirements R1 and R2 require clarification to remove ambiguities regarding the intent discussed in the rationale box and how language within that requirement could be interpreted. As an example, the rationale box associated with Requirement R1 indicates that the sub-requirements of 1.2 are processes, but certain sub-requirements appear to require provisions - not processes. Also, the requirement should address the need to develop “a process to mitigate Emergencies” rather

Organization	Yes or No	Question 1 Comment
		than “a process to prepare for mitigating”. This should be clarified. Additionally, the meaning of “Reduction of Internal Utility Energy Use” remains unclear and should either be clarified or deleted. The SRC therefore proposes the following revisions to address the above concerns:R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies within its Transmission Operator Area. The Operating Plan shall include the following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Emergency Operating Plan; 1.2. Process for notification to the Reliability Coordinator that it is experiencing an operating Emergency and the associated system conditions; 1.3 Processes to mitigate Emergencies, including: 1.3.1. Management of Transmission and generation outages; 1.3.2. Transmission system reconfiguration; 1.3.3. Redispatch of generation request; and 1.3.4. Reliability impacts of extreme weather conditions 1.3.5 Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergency. R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Process for notification to the Reliability Coordinator that it is experiencing a Capacity Emergency or Energy Emergency and the associated system conditions; 2.3 Processes to mitigate Emergencies including: 2.3.1. Requesting an Energy Emergency Alert, per Attachment 1; 2.3.2. Managing generating resources in its Balancing Authority Area to address: 2.3.2.1. Capability and availability; 2.3.2.2. Known fuel supply and

Organization	Yes or No	Question 1 Comment
		inventory concerns; 2.3.2.3. Fuel switching capabilities; and 2.3.2.4. Environmental constraints. 2.3.3. Public appeals for voluntary Load reductions; 2.3.5. Coordination with government agencies regarding known programs that may facilitate energy reductions; 2.3.6. Use of Interruptible Load, curtailable Load and demand response; 2.3.7. Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergent; and 2.3.8. Reliability impacts of extreme weather conditions. Corresponding revisions to VSLs and associated measures are also recommended.2. The SRC believes that Requirement R3 requires streamlining and clarification to ensure clarity. As an example, the SRC is not clear regarding what is meant by "Review each submitted Operating Plan for coordination". The SRC proposes the following revisions to address the above concerns:R3. Within 30 calendar days of receipt of an Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority, the Reliability Coordinator shall:3.1.1 Review each submitted Operating Plan: 3.1.1.1 For compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans; and3.1.1.2. To avoid risk to Wide Area reliability; and 3.1.2. Notify each Balancing Authority and Transmission Operator of the results of its review. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] Corresponding revisions to VSLs and associated measures are also recommended.
Independent Electricity System Operator	No	We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that:3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; andWe are not clear on what it means by "Review each submitted Operating Plan for coordination". Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the

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		review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
Kansas City Power and Light	No	R1/R2 - While we have seen the ‘develop, maintain and implement’ language in other standards, we continue to be a bit unsure just how we are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change ‘Notification to the Reliability Coordinator...’ to ‘Notification of its Reliability Coordinator...’.R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: ‘Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.’Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace ‘...how you will make a notification to the...’ with ‘...when the Transmission Operator must notify its...’.R2-Insert ‘within its Balancing Authority Area’ at the end of the 1st sentence of the requirement.R2.2.1- Change ‘Notification

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		to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.'Rational for Requirement R2 - Delete 'Emergency' in 'Emergency Operating Plan' in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase 'as much as possible' off with commas as was done in the Rationale for Requirement R1.R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: '...shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority...'. Also, hyphenate '30-calendar days'.R3.1.1 - Add 'within its Reliability Coordinator Area' at the end of the Subpart.R3.1.2 - Modify the Subpart to the following: 'Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and'R3.1.3 - Add 'of its review' at the end of the Subpart.Rationale for R3 - In the 3rd line, change 'require' to 'requires'. Capitalize 'Emergencies' in the last line.M3 - Hyphenate '30-calendar days'.M4 - Replace 'emails' in the 2nd line with 'e-mails' to make it consistent with the usage in M3.R5/M5 - Insert the phrase 'within its Reliability Coordinator Area' after 'Balancing Authority' in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. 'Neighboring' is used in conjunction with Reliability Coordinator at the end of this

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		requirement. 'Adjacent' is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term 'impacted' has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There's a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term 'impacted'. Modify Measure M5 to be consistent with the suggested changes to Requirement R5.The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. 'Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability

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		Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.' Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn't this requirement really a holdover from EOP-002-3.1, R8?
American Electric Power	No	R1.2.2 and R1.2.4 specifies generation actions to be taken the Transmission Operator. These requirements hold the TOP responsible for "cancellation or recall of Transmission and generation outages" and the "Redispatch of generation request". AEP does not believe it is within the TOP's jurisdiction to perform such actions within their Transmission Operator Plan. Rather, AEP believes it would be the BA's responsibility to recall generation outages or redispatch generation. AEP recommends that R.1.2.2 be changed so the BA is solely responsible for such actions, perhaps by breaking out the generation actions from R1 and making them separate from the transmission actions (possibly by adding them to the R2 requirements where the BA is responsible).In regard to R1.2.2 and R1.2.4, AEP believes the BA needs to be responsible for generation outages and the redispatch of generation. For the TOP, existing TLR or market based congestion management processes would re-dispatch generation. In an Emergency event where a generator would need redispatced for a local transmission problem, the TOP may need to contact the Reliability Coordinator. R1.2.5 could have a large impact on Transmission Operators' installed base of manual load shedding / automatic Load shedding systems. AEP recommends the SDT take a poll on the impact using the Transmission Forum. R4 mentions a time period specified by its Reliability Coordinator. AEP believes this should incorporate a working dialog between the Reliability Coordinator and the Transmission Operator and Balancing Authority. As such AEP believes a *mutually agreed time period* would be more appropriate. Such language is used in the EOP 005-2 standard.

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	No	The standard drafting team's changes resulted in a much better standard overall. However, the team did not make any change to the use of the defined term Emergency. Since this term is broad enough to include most transmission system faults, it is over inclusive and could impose a significant burden on entities as they try to demonstrate implementation of the Operating Plan. Leaving each entity to define Emergency may lead to ambiguity with enforcement later. It would be better to address the issue now - either in the standard (perhaps by expressly allowing entities to define the scope of the term) or by redefining the term to include some measure of significance.
NIPSCO	No	EOP-011-1 covers the long-term planning horizon and we are not quite sure why, looking at the criteria. Please clarify. How does the "Operating Plan" required under EOP-011-1 R1 for mitigating operating emergencies in the TOP area mesh with the Operating Plan required under the new TOP-002-4 R2 and the one that has to be implemented under TOP-001-3 R14? Are these Operating Plans one in the same? If so, then the requirement EOP-011-1 R1 is redundant and should be deleted as this creates confusion. The Operating Plan for EOP-011-1 R1 requires RC review, but the Operating Plan mentioned in TOP-002 does not. This is not clear and should be addressed.Thanks
ReliabilityFirst	No	ReliabilityFirst votes in the Negative due to the non-enforceable language in R1 and R2 and offers the following comments for consideration:1. Requirement R1 and R2 - ReliabilityFirst appreciates the SDT removing the “Reliability Coordinator-approved” language but still questions “Reliability Coordinator-reviewed” language. In the scenario where the Reliability Coordinator does not review the Operating Plan, is the Transmission Owner (R1) or Balancing Authority (R2) non-compliant? Furthermore, there is no corresponding requirement for the TO or BA to supply the Operating Plan

Organization	Yes or No	Question 1 Comment
		to the Reliability Coordinator. To address both of ReliabilityFirst's concerns, ReliabilityFirst suggest the following language: "Each Transmission Operator shall develop, maintain, and implement an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area [and make available to the Reliability Coordinator for review]. The Operating Plan shall include the following, as applicable:" 2. Requirement R3 Part 3.1.3 - In order for consistency between R3 and R4 regarding the Reliability Coordinator specifying a time period for the TOP or BA to address identified reliability risks, ReliabilityFirst recommends modifying R3 Part 3.1.3 to state; "Notify each Balancing Authority and Transmission Operator of the results [and time period for resubmittal if reliability risks are identified]."
We Energies	No	R1 and R2: The use of the term [implement] in the opening sentences of R1 and R2 should be removed and replaced with an additional sentence; the BA/TOP [shall act in accordance with their plan to mitigate a Capacity Emergency or Energy Emergency.]. The word implement can be interpreted to create a pre-emergency obligation (to train or provide other evidence of awareness) relative to the developed and maintained Operating Plan. To an extent, the measures for R1 and R2 address this issue with the phrase, [for times when an Emergency has occurred]. However, replacing implement with shall act in accordance with adds clarity to the requirement. R1.2.5 and R2.2.8: The requirements include language to [minimize] overlap of manual and automatic load shed and require that manual load shed be capable of being implemented in a [timeframe adequate for mitigating the Emergency.] This language creates requirements that are ambiguous and would be difficult to both audit and prove compliance. Additionally, the SDT's goal of keeping manual and automatic Load shed schemes as separate as possible does not fully consider the interaction between a TOP's UVLS and a BA's UFLS schemes. A BA maintaining separation between their manual load shed and UFLS, may have manual load shed plans that remove a TOP's UVLS. Additionally, the objective of a BA using

Organization	Yes or No	Question 1 Comment
		manual load shed to respond to Energy Emergencies and Capacity Emergencies is to balance the BA. UFLS under non-islanded conditions has a broader purpose of maintaining the entire Interconnection.R2.2.8: This requirement combines the Balancing Authority functional model role and the implementation of operator controlled manual Load shedding, which aligns with the DP role. The requirement is written assuming a vertically integrated utility with both BA and DP roles. When considering the functional model, a BA would affect manual load shed through the use of an Operating Instruction to a DP to shed the load. A non-vertically integrated BA does not have the means to directly affect load shed without an Operating Instruction.R3. The requirement does not identify a periodicity or requirements for ongoing RC review of Operating Plans, nor does it address timing of Operating Plan submittal to the RC. As the requirement is written, the first TOP or BA to submit a plan will receive the results of the RC review within 30 days. It is not clear to whom will the RC compare initially submitted plan if all the BA's or TOPs do not submit their plans at the same time. Alternately, if all BA / TOP plans are submitted to the RC at the same time, how effective will an RC review be if they are required complete their review within 30 calendar days? EOP 005-2 contains a well thought out process for periodicity and timing of submitting plans to an RC and should be considered as a template for this requirement.R4. As written, the requirement does not establish a set timeframe for the BA/TOP to address reliability risks identified during the RC review of the Operating Plans. R5: The phrase [and neighboring Reliability Coordinators] should be replaced with [and adjacent Reliability Coordinators.] This would be consistent with the notification process in Attachment 1, which requires the RC to [also notify all adjacent Reliability Coordinators.]
Salt River Project	No	SRP appreciated the efforts at revising the requirement for the Operating Plan to be approved by the Reliability Coordinator to just require reviewal

Organization	Yes or No	Question 1 Comment
		of the Operating Plan. However, there is no time frame or periodicity mentioned for when the Operating Plan should be reviewed. Please address when the Operating Plan needs to be reviewed.
Manitoba Hydro	No	Requirement R4 - the requirement that each Transmission Operator and Balancing Authority shall “address” any reliability risks... should berevised to state that each Transmission Operator and Balancing Authority shall “make a good faith attempt to address” any reliability risks identified by its Reliability Coordinator pursuant to Requirment R3. Requirment R3.1.1 requires the Reliability Coordinator to review each submitted Operating Plan on the basis of compatability and inter-dependency with other Balancing Authorities’ and Transmission Operators’ Operating Plans.. This implies that a given Transmission Operator or Balancing Authority may need to negotiate a modified approach with other Transmission Operators or Balancing Authorities . Since one party cannot compel an agreement with another party, only god faith efforts can be made to resolve an incompatibility . There is no mechanism or criteria specified in R3 for the Reliability Coordinator to pick one plan over another if two or more operating plans are inconsistent.
Exelon Companies	No	Requirement 1 states theTransmission Operator shall develop, maintain and implement an Operating Plan that includes: Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency.We are concerned with the use of “minimizes” and “adequate timeframe”. This is open to interpretaion by compliance audit staff.
Texas Reliability Entity	No	In Requirement R1, use of the term “Transmission Operator Area” appears to assume that generation supply physically located within a Transmission Operator’s footprint is part of their “Transmission Operator Area.” As

Organization	Yes or No	Question 1 Comment
		currently defined, “Transmission Operator Area” is the collection of Transmission assets that the Transmission Operator is responsible for operating. Using this definition in the requirement may create a reliability gap if a TOP determines that generation facilities are not included in the Transmission Operator Area because they don't meet the definition of Transmission. For example, in the ERCOT region some TOPs have argued that certain generation units are not in their Transmission Operator Area and therefore the TOP is not required to monitor those facilities. A TOP’s Operating Plan for mitigating operating Emergencies should include all applicable generation supply (per the FERC-approved definition of Emergency) to eliminate any potential reliability gaps. Accordingly, Texas RE offers several options to resolve this reliability gap concern: 1) Revise the current approved definition of “Transmission Operator Area” to add language that addresses the inclusion of any generation supply that may impact the Transmission Operator’s “Area.” Proposed revision: “The collection of Transmission Facilities over which the Transmission Operator is responsible for operating, as well as generation, distribution and loads that have power flowing into or from these Facilities.”2) Add the phrase “connected to the Transmission Operator Area” after any usage of the word “generation” within the requirements (Example: R 1.2.2 could be revised to “Cancellation or recall of outages of Transmission or generation connected to the Transmission Operator Area.3) Add technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area.Option 1 is Texas RE’s preferred result, but at a minimum, Option 3 should be incorporated by the SDT.
Tri-State Generation and Transmission Association, Inc.	No	While TSGT agrees that the language in R3 is better the Standard Drafting Team has created a one sided requirement with R4. By not requiring justification or coordination from the RC to the BA/TOP when they feel they have identified a reliabililty risk within the entities Operating Plan. With these changes they have also removed responsibility from the RC to the

Organization	Yes or No	Question 1 Comment
		TOP/BA by not requiring the RC to officially approve the plan yet the TOP/BA must address the RC's feedback. TSGT suggests the SDT come up with language that promotes a cooperative effort between the TOP/BA and the RC.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	Thought the NSRF agrees with the re-write of EOP-011-1, please note the following discrepancy. Within R5, the word "impaced" has been removed but remains in the High and Severe VSL, and in Attachment 1, section 2.2, 3.2, 3.4.1 and 0.1. The NSRF recommends that "impacted" be re-inserted into R5 to provide clarity and inorder to be aligned with the remaining parts of the proposed Standard.
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	For R5, Southern suggests revising the requirement to add clarity. Suggested wording: R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area within 30 minutes from the time of receiving the Emergency notification,. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Bonneville Power Administration	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
Hydro-Quebec TransEnergie	Yes	
South Carolina Electric & Gas	Yes	

2. Attachment 1. Do you agree with the changes made to Attachment 1 of EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue

Summary Consideration: Thank you for your comments.

Arizona Public Service Company, Northeast Power Council and Hydro-Quebec commented on the bullet point “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements” in the “Circumstances” of EEA 2. The EOP SDT’s intent is that in an EEA 2, an energy deficient Balancing Authority is unable to meet all of its energy requirements, but has addressed that condition by utilizing Demand response and any other Load management procedures it may have access to. It is also making emergency purchases from other Balancing Authorities to help remedy its situation. In an EEA 2, the Balancing Authority is still able to serve and provide regulation for its remaining Load and maintain its minimum Contingency Reserves; thus, it should not be a burden to the Interconnection. The use of Contingency Reserve margin as a dividing line between an EEA 2 and EEA 3 means that in an EEA 2, a Balancing Authority has taken Load management actions – short of “Load shedding” – but can still balance and control for its remaining firm Load and meet its minimum Contingency Reserve requirements – but just barely. Once a Balancing Authority has to dip into its Contingency Reserve margin for Load service or for regulation (or has to shed Load for some other reason), it is in an EEA 3. At that point, it is likely to become a burden to the Interconnection; that determination would be made by the Reliability Coordinator, and not by an individual Balancing Authority. Additional clarification to the bullet point “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements” in the “Circumstances” of EEA 2: the EOP SDT maintains that the current language provides a Balancing Authority flexibility in defining their "minimum" Contingency Reserves at or above their most severe single contingency (MSSC), as they see necessary to manage reliability within their Balancing Authority Area. The EOP SDT finds it important to maintain this flexibility for the varying needs of the Balancing Authorities s across Interconnections.

In addressing several comments received, the EOP SDT has revised Attachment 1 to replace “adjacent” with “neighboring.” The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Dominion, ACES Standards Collaborators and NYISO submitted comments pertaining to reevaluation and revision of SOLs and IROLs during an EEA 3. The EOP SDT has received industry stakeholder consensus with regard to this language and the drafted language will be retained. Section 3.3 only addresses re-evaluation of SOL/IROL under an EEA 3. There is no requirement to restore previous SOL/IROL while under an EEA 3. Under Section 3.4, SOL and IROL can be returned to its pre-Emergency SOLs or IROLs condition upon a termination of the alert level.

Southern Company's requested clarification around pre and post contingency firm Load shed actions during an EEA 3. The EOP SDT retains the language as drafted; an EEA 3 is, by definition, when "Firm Load interruption is imminent or in progress."

SPP and Duke Energy requested justification for the changing "Operating Reserves" to "Contingency Reserves." For clarity, and to responds to comments previously received from industry stakeholders, which revealed a wide range of interpretations as to the meaning of the existing language of EOP-002-3.1 with respect to shedding Load, the EOP SDT revised the drafted language from the term "Operating Reserves" to "Contingency Reserves" and moved "Contingency Reserves" to EEA 3 to define a circumstance for when an entity may be considering shedding Load, as well as to align EOP-011-1 with BAL-002-2.

SPP further provided language revisions to 3.2, 3.3 and 3.3.1 of Attachment 1. The EOP SDT appreciates your comments and suggestions but maintains the drafted language provides sufficient clarity and will retain the language as drafted.

SPP asks: "Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions?" The EOP SDT's response is: ***No***. To clarify, the EOP SDT is stating that it is preferable to use your Contingency Reserve margins to serve Load; and, when you do, you are at EEA Level 3. It is outside the scope of the EOP SDT to define how every Balancing Authority will respond to the EEA conditions. Each Balancing Authority would define how to respond to an EEA 3 condition within their plan(s).

An additional question raised by SPP is: "How does one determine the level of risk to the interconnection which would drive a Balancing Authority to shed Load?" The EOP SDT cannot know all of the triggering events for all scenarios. It would be the responsibility of the Reliability Coordinator and/or the Balancing Authority to make such determinations and direct the BA to take appropriate action.

Comments were received to clarify the number of EEA levels (three v. four). The EOP SDT retains the language drafted as three EEA levels. Alert 0 is normal operations, not an Emergency.

Duke Energy suggested language revision to A. General Responsibilities (1.) Initiation by Reliability Coordinator and (2) Notification in Attachment 1. The EOP SDT appreciates Duke Energy's suggested language revision, but retains the drafted language, as it provides sufficient clarity. The notification is only that an EEA has been declared. Requirements R1 and R2 specify notification of System conditions.

Texas RE submitted a request for clarification of EEA 2.1; and Duke Energy suggested removing RCIS for 2.1 and 2.2 of EEA 2, 3.4.1 of EEA 3, and 0.1 of EEA 0 to be consistent with the removal of RCIS in Section A, General Responsibilities. The EOP SDT notes that the RCIS is an industry-wide tool and a defined NERC Glossary term. The EOP SDT does not believe additional language suggested provides further clarity of EEA 2, 2.1.

Duke Energy commented to retain the LSE's ability to request that a Reliability Coordinator declare an EEA. The EOP SDT has received industry consensus that the LSE be removed from the standard.

Duke Energy commented on drafting of a white paper or guidance document for clarity of the actions to be taken at each EEA level. The EOP SDT maintains that Attachment 1 defines the actions to be taken and that the rationales within the Attachment provide sufficient clarity.

Duke Energy additionally suggested a language revision from “terminates” to “downgraded” in Section 3.2 of Attachment 1. The EOP SDT maintains that “terminate” is the correct term to be used and retains the drafted language of Attachment 1. Entities do not necessarily move from EEA 3 to EEA 2, an entity may move to an Alert 0 condition.

Duke Energy further suggests language revision to 3.4.1 of Attachment 1, that notification by a Balancing Authority has already been established as part of 3.4. The EOP SDT believes the drafted language is sufficient in clarity and the proposed modification does not add further clarity.

ACES Standards Collaborators requested clarification of Section 3.3, would it be inconsistent with FAC-014 and FAC-011. The EOP SDT does not view Section 3.3. as an inconsistency with the stated FAC standards; EOP-011-1 addresses Emergencies; whereas the FAC standards address establishment of SOLs and IROLs.

ACES Standards Collaborators requested clarification as to the Balancing Authority and its communications with other Balancing Authorities in an EEA 2. The Balancing Authority is fully aware of its contracts with other Balancing Authorities and market participants. This communication is more efficient than using the Reliability Coordinator.

SRC noted that 2.3 of Attachment 1 is redundant to requirements in IRO-014-3. Attachment 1 is not imposing an additional requirement. IRO-014-3 limits the notification to “other impacted” Reliability Coordinators. The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in it Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

NYISO suggested a language revision in Section 2.4 of Attachment 1 to “…in order to mitigate the emergency.” The EOP SDT retains the drafted language of the Attachment. The proposed revision does not add further clarity to Section 2.4.

NYISO requested clarity of Section 2.5.1 of Attachment 1, specifically if this includes quick start units used to maintain Contingency Reserve while offline. The intent of the EOP SDT is that under EEA 2 conditions, *all* units not being held in to meet minimum Contingency Reserve requirements should be online and capable of producing power prior to moving to an EEA 3. When an EEA is terminated, an entity is in normal operations and covering Load and Operating Reserves.

Texas RE commented on responsibility element in EEA 3 and recommended language revision to add “Sharing information on resource availability” within the responsibilities. The EOP SDT maintains the drafted language of Attachment 1 provides sufficient clarity; Paragraph 3.1 states, “Continue actions from EEA 2.”

The EOP SDT made the following revisions to Attachment 1 of EOP-011-1 based on industry stakeholder comments/suggestions and clarification requests:

Rationale box for Introductions:

"EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specifications did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired."

Sharing information on resource availability. Other ~~The~~ Reliability Coordinators of ~~a~~ Balancing ~~Authority~~ Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

Rationale box was added to EEA 3 and reads as:

Rationale for EEA 3:

This rationale *was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.*

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	We appreciate that the SDT addressed our comments regarding the need for definitive triggers between the EEA levels. However, with the inclusion of the final bullet of the circumstances section on EEA 2, AZPS believes that as written, the Circumstances together, where an entity is energy deficient and still maintaining their reserves at the same time, would be inappropriately burdening the interconnection. Is this the intent of the change?, If not, additional clarification around the Circumstances is requested.
Northeast Power Coordinating Council	No	In EEA 2, a bullet was added addressing the ability of the BA to maintain “minimum Contingency Reserve requirements”. This could be interpreted in two ways because of the use of the word “minimum”. It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA’s Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT’s intent, then suggest the following language: “An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement.”The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT’s intent, we then suggest the following language: “An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted.”For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained in all cases in order to provide minimum levels of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.

Organization	Yes or No	Question 2 Comment
Dominion	No	Suggest revising Notification so that it is consistent with the standard. The standard uses 'neighboring RCs' whereas the attachment uses "adjacent RCs". Under EEA, at 2.4 - Dominion believes this occurs only where a SOL or IROL is restricting the deficient Balancing Authority's ability to import energy necessary to mitigate its Capacity Emergencies and Energy Emergencies. If so, suggest SDT consider explicitly stating this.
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 understands the SDT's approach in the revised Attachment 1, but we think there is still sufficient confusion in the industry around pre and post contingency firm load shed actions during an EEA 3. We request that the SDT provide some clarity around these actions in the Attachment 1 as suggested below but at a minimum in the consideration of comments, whitepaper, or some other form. Based on the current draft, if an entity experiences a situation where its Contingency Reserves fall below the minimum, the entity would be in an EEA3. Just because an entity's Contingency Reserves have fallen below the minimum should not mean, however, that firm load shed is required pre-contingency in order to restore the minimum generation-side contingency reserves. Southern recommends that the "Circumstances" for EEA3 be revised to the following:The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements AND foresees the use of firm load shed to respond post-contingency to a generation contingency event or to recover generation/load balance pre-contingency.
PPL NERC Registered Affiliates	No	Attachment A, section B.2.1 - This section is preceded by the sentence, "During an EEA 2, RCs and BAs have the following responsibilities," yet this section also includes responsibilities of market participants. What obligation do the market participants (PSEs) have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Due to the ambiguity of the market participant responsibilities in the attachment and the fact that there are no requirements of "market participants" within the standard, PPL Companies recommend that the market participant responsibilities be removed from the

Organization	Yes or No	Question 2 Comment
		attachment entirely. Attachment A, section B.2.1 - This section states that, "the requesting BA shall communicate its needs to other BAs and market participants," but it does not describe how the BA is to make this communication. It appears this is a real time communication between the requesting BA and market participants (PSEs) but it is not clear over what medium and timeframe the communication is to occur. Attachment A, section B.2.5.1 - The mention of "all available generation units" is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1.
Associated Electric Cooperative, Inc.	No	AECI agrees with SPP Comments
SPP Standards Review Group	No	Introduction - In what appears to be the rationale for the introduction, insert the phrase 'as permitted in its transmission tariff' following 'request' in the 2nd line of the paragraph.General Responsibilities/Notification - Notification is to go out to all 'adjacent' Reliability Coordinators. As pointed out in Question 1 above, the term used in Requirement R5 is 'neighboring'. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms 'adjacent' and 'neighboring'.EEA Levels - Throughout the remainder of Attachment 1, an extra space pops up between 'Reliability Coordinator' and 's' in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0.EEA 2 - In the paragraph immediately above 2.1, delete the extra 's' after Balancing Authorities.2.3 - We suggest rewording the beginning of this sentence to 'Other Reliability Coordinators of Balancing Authorities with available resources...'. Otherwise a Reliability Coordinator is required to communicate with itself.2.4 - Insert 'to-service' between 'return' and 'any' in the 3rd line.Rationale for EEA 2-Capitalize Contingency Reserves.EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT's effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2.

Organization	Yes or No	Question 2 Comment
		The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT's justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: 'First, The previous language used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.' We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That

Organization	Yes or No	Question 2 Comment
		will help alleviate any misunderstanding which may exist as well as provide a permanent record of why the change was made.3.2 - We suggest rewording the last three lines of this section to read '...Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.'3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: 'Transmission Operator whose Transmission Owner's equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner's equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to 'take whatever actions are necessary to mitigate any undue risk to the Interconnection'. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load?3.4 - Either delete the 'the' in front of 'Systems' in the 2nd line or change 'Systems' to 'System'.3.4.1 - We suggest the following changes: 'Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.'
Duke Energy	No	(1)Duke Energy suggests the following revision to A.1. of Attachment 1:"1. Declaration by Reliability Coordinator. An Energy Emergency Alert (EEA) may be

Organization	Yes or No	Question 2 Comment
		declared only by a Reliability Coordinator at 1) the Reliability Coordinator's own discretion, or 2) upon the request of the Balancing Authority or Load Serving Entity." We still believe that at a minimum, EOP-011 should retain the LSE's ability to request that an RC declare an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. In addition, LSEs who are not part of ISO/RTO markets should still have the ability to notify the RC or BA when they are experiencing an energy emergency. Finally, we believe that the RC is responsible for declaring an EEA and the associated notifications. The BA or LSE is responsible for initiating the EEA through the notification to the RC.(2)Duke Energy suggests the following revision to A.2. of Attachment 1:"Notification. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all adjacent Reliability Coordinators of system conditions."We believe the added language provides additional clarity.(3)Duke Energy suggests removing RCIS for 2.1 and 2.2 of EEA 2, 3.4.1 of EEA 3, and 0.1 of EEA 0 to be consistent with the removal of RCIS in Section A, General Responsibilities.(4)Duke Energy believes that a white paper or guidance document is needed to clarify the necessary actions taken at each EEA level. As written, it is difficult to identify those actions and a white paper or guidance document would be beneficial.(5)There appear to be typos within the attachment and suggest replacing "Reliability Coordinator s" with "Reliability Coordinator's "(6) Duke Energy suggests replacing "terminates" with "downgraded" in section 3.2 of Attachment 1. We believe this change better clarifies the SDT's intent and is also consistent with the language in 3.4.1. (7) Duke Energy suggests replacing "requirements" with "actions" in section 3.3 of Attachment 1. We believe this change better clarifies the SDT's intent.(8)Duke energy suggests the following revision to 3.4.1 of Attachment 1:"Notification of other parties. Upon downgrading the alert by the Reliability Coordinator, the Reliability Coordinator shall notify the

Organization	Yes or No	Question 2 Comment
		impacted Reliability Coordinator’s, Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.”We believe that the notification piece by a BA has already been established as part of 3.4 and is not necessary in 3.4.1.(9)Duke Energy suggests replacing “Operating Reserves” with “Contingency Reserves” to be consistent with maintaining Contingency Reserves as outlined in Attachment 1. If the SDT believes that Operating Reserve is the appropriate term, can the SDT explain the rationale behind using Operating Reserve instead of Contingency Reserve?
ACES Standards Collaborators	No	(1) We question the re-evaluation and revision of SOLs and IROLs during an EEA 3. First, this step should be completed prior to entering EEA3 because load shed is already occurring or is imminent. We understand that there is a step 2.4 under EEA 2 that considers that impact of Transmission outages on IROLs and SOLs but it does not call for re-evaluation or revising of IROLs and SOLs even if Transmission Elements are returned to service. By the time the situation reaches EEA 3, load shedding is occurring. If there are activities, such as reevaluating SOLs (e.g. using a shorter duration emergency limit) to prevent load shedding, the re-evaluation should occur during should be done during EEA 2 with implementation of the new limit in EEA 3. (2) We believe section 3.3.1 and the last sentence of 3.3 should be struck as they are ambiguous and cause confusion. First, section 3.3.1 appears to limit use of revised SOLs and IROLs until after load shed occurs. The bottom line is revised IROLs and SOLs should be used to prevent load shed not mitigate it once it has occurred. The RC can revise IROLs at any and the TOP can revise SOLs at anytime as long as they are consistent with the RC’s SOLs methodology. (3) Section 3.3 is inconsistent with FAC-014 and FAC-011. FAC-014 requires the RC to establish an SOL methodology and FAC-011 requires the RC to establish IROLs and the TOP to establish SOLs consistent with the methodology. The RC does not require TOP agreement to modify IROLs as they have the authority to establish an IROL. The only real issue here is that the RC and TOP need to make sure they are not violating the TOP’s Facility Ratings established per their Facility Ratings methodology (FAC-008). FAC-011 R1.2 already requires this. We suggest simply stating that “Reevaluation of SOLs and IROLs shall

Organization	Yes or No	Question 2 Comment
		be coordinated with other Reliability Coordinators and Transmission Operators consistent with the RC's SOL Methodology and TO's Facility Ratings Methodology." (4) We question why a BA has to communicate its needs to other BAs in EEA2. They should only be required to notify its RC who then communicates the issue via RCIS which will notify all BAs at the same time. This avoids the compliance issue of whether the RC notification per the RCIS satisfies the BA's obligation. (5) There are several extraneous "s" in the attachment usually after Reliability Coordinator or Balancing Authority. Look at the last sentence of EEA2 for example.
Peak Reliability	No	The notification section should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies - just those that need to know such information.
ISO/RTO Council Standards Review Committee (SRC)	No	1. The SRC notes that Subsection 2.3 is redundant with the requirements contained in IRO-014-3. To avoid duplication, it is recommended that this subsection be removed.2. The SRC notes two minor typographical errors: a. Sections B and subsections 2.2, 3, 3.1, 3.3, and 0.1 appear to contain an inadvertent space in the added term "Reliability Coordinator s". This space should be removed.b. The third sentence in Section B is not part of a requirement and is, therefore, unnecessary and should be removed.c. It is recommended that the circumstances underlying an EEA 2 be clarified. The following revisions are proposed:Circumstances: o The Balancing Authority is an energy deficient Balancing Authority ando Is no longer able to meet energy requirements. o Has implemented its Operating Plan to mitigate Emergencies. o Is still able to maintain minimum Contingency Reserve requirements. d. Section 3.3.1 appears to contain an inadvertent word "it" before "will immediately take..." This should be removed from Section 3.3.1.
Kansas City Power and Light	No	Introduction - In what appears to be the rationale for the introduction, insert the phrase 'as permitted in its transmission tariff' following 'request' in the 2nd line of the paragraph.General Responsibilities/Notification - Notification is to go out to all 'adjacent' Reliability Coordinators. As pointed out in Question 1 above, the term used

Organization	Yes or No	Question 2 Comment
		in Requirement R5 is ‘neighboring’. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms ‘adjacent’ and ‘neighboring’.EEA Levels - Throughout the remainder of Attachment 1, an extra space pops up between ‘Reliability Coordinator’ and ‘s’ in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0.EEA 2 - In the paragraph immediately above 2.1, delete the extra ‘s’ after Balancing Authorities.2.3 - We suggest rewording the beginning of this sentence to ‘Other Reliability Coordinators of Balancing Authorities with available resources...’. Otherwise a Reliability Coordinator is required to communicate with itself.2.4 - Insert ‘to-service’ between ‘return’ and ‘any’ in the 3rd line.Rationale for EEA 2-Capitalize Contingency Reserves.EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT’s effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2. The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT’s justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: ‘First, The previous language used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting

Organization	Yes or No	Question 2 Comment
		Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA.Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.’ We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That will help alleviate any misunderstanding which may exist.3.2 - We suggest rewording the last three lines of this section to read ‘...Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.’3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: ‘Transmission Operator whose Transmission Owner’s equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner’s equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is

Organization	Yes or No	Question 2 Comment
		necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to 'take whatever actions are necessary to mitigate any undue risk to the Interconnection'. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load?3.4 - Either delete the 'the' in front of 'Systems' in the 2nd line or change 'Systems' to 'System'.3.4.1 - We suggest the following changes: 'Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.'
Hydro-Quebec TransEnergie	No	In EEA 2, a bullet was added addressing the ability of the BA to maintain "minimum Contingency Reserve requirements". This could be interpreted in two ways because of the use of the word "minimum". It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA's Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT's intent, then suggest the following language: "An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement."The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT's intent, we then suggest the following language: "An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted."For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained

Organization	Yes or No	Question 2 Comment
		in all cases in order to provide minimum levels of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.
New York Independent System Operator	No	The NYISO proposes the following additions:Section 2.4 should include the phrase: ".. in order to mitigate the energy emergency. "Section 2.5.1 requires all generators to be on-line. The NYISO would like to clarify that this does not include quick start units (e.g., 10 minute GT resources) used to maintain contingency reserve while off-line?Section 3.3 indicates that revised SOL/IROLs would only be revised as long as the EEA 3 condition exists. The NYISO is unclear on what conditions related to an EEA 3 would require an entity to restore previous SOL/IROL's. If a new SOL/IROL was developed would that not be valid for the existing conditions?
Texas Reliability Entity	No	1) Attachment 1 contains terms that are not consistent with the language in the requirements. The following comments identify the areas of inconsistency: Section A, Item 2: Attachment 1, Section A. General Responsibilities, Item 2. Notification, last sentence uses the term adjacent RCs. Based on the Rationale for (2) Notification, it appears that the use of the term “adjacent” is aligned with IRO-014-3, Requirement R1 which uses the term. However, EOP-001-1 Requirement R5 uses the term neighboring RCs. Texas RE recommends the term “adjacent” be replaced with “neighboring” in Section A, Item 2. Section B. EEA Levels, 2. EEA 2, 2.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.4.1 Notification of other parties uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, Alert 0 - Termination, 0.1 Notification uses the term impacted RCs, BAs and TOPs. However, Requirement R5

Organization	Yes or No	Question 2 Comment
		replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” 2) Section B, EEA Levels, 2. EEA 2, 2.1, Texas RE suggests the addition of clarifiying language to more clearly indicate the RC responsibility as follows: “Upon request [of an EEA] from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.” 3) Section B, EEA Levels, 2. EEA 2, 2.4 Texas RE suggests that “Transmission Operator” should be “Transmission Operator(s).” 4) Section B, EEA Levels, 3. EEA 3, Texas RE suggests there is a responsibility missing from the EEA Level 3 list and recommends adding the responsibility of “Sharing information on resource availability” (as listed within EEA Level 2) within EEA Level 3 responsibilities.
MRO NERC Standards Review Forum	Yes	Please see question 1.
Tennessee Valley Authority	Yes	
FirstEnergycorp	Yes	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with all the changes. Just a typo: the word “it” before “will immediately take...” should be removed from Section 3.3.1.
DTE Electric	Yes	
Bonneville Power Administration	Yes	
Independent Electricity System Operator	Yes	We agree with all the changes. Just a typo: the word “it” before “will immediately take...” should be removed from Section 3.3.1.
Idaho Power	Yes	

Organization	Yes or No	Question 2 Comment
Tacoma Power	Yes	
We Energies	Yes	
Salt River Project	Yes	
Manitoba Hydro	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

3. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The EOP SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for EOP-011-1? If you do not agree, please explain why and provide recommended changes**

Summary Consideration: Thank you for your comments.

Dominion suggested removal of the term “impacted” from the Requirement R5 High/Severe VSL for consistency with the change made to Requirement R5. The EOP SDT agrees with this suggestion, and has made the revision.

Several commenters expressed concern regarding the High and Severe VSLs for Requirement R5, specifically regarding the time associated with the Requirements. The EOP SDT maintains that notifications under Emergency conditions are imperative and that violation of this requirement merits a High VSL.

SPP Standards Review Group suggested language changes for the Moderate and High VSLs for consistency with the Requirement and other associated documents. The EOP SDT revised the language as appropriate. SPP also recommended language revisions to Requirement R4, however, the EOP SDT does not believe it is necessary to use “responsible entity.”

DTE Electric suggested revising the VSLs associated with R3 to conform to the requirement language. The EOP SDT agrees with the suggestion and has revised the language as appropriate.

ACES Standards Collaborators suggested adding a Lower VSL table for Requirement R1 as well as adding a Lower and Moderate VSL for Requirement R4. The EOP SDT believes that the VSLs are appropriate as written. Also, ACES Standards Collaborators, along with Texas Reliability Entity, suggested revising the language used in the Severe VSL for Requirement R5 to conform with the language used in Requirement R5. The EOP SDT revised the language as per Requirement R5 which uses the term “neighboring.”

Exelon Companies expressed concern that the VSLs for Requirement R1 do not refer to particular Parts of the Requirement. The EOP SDT believes that the VSLs are appropriate as written. The use of “as applicable” in the requirement precludes the use of subparts in the VSL.

Organization	Yes or No	Question 3 Comment
Dominion	No	R5 High/Severe VSL have ‘notify impacted RCs’, the word impacted needs to be removed as it was removed in R5 and the VLS needs to be updated to match R5.

Organization	Yes or No	Question 3 Comment
FirstEnergycorp	No	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5.In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed "failed to notify". Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
SPP Standards Review Group	No	R1 - Change the Moderate VSL to state '...to mitigate operating Emergencies in its Transmission Operator Area...' to be consistent with the requirement and the other VSLs for this requirement. Change '...the Reliability Coordinator.' in the High VSL to '...its Reliability Coordinator.'R2 - Add the phrase 'within its Balancing Authority Area' following the usage of 'Emergencies' in the Moderate, High and Severe VSLs for Requirement R2.R3- Insert '-calendar' following '30' in the High VSL.R4 - Replace 'Transmission Operator and Balancing Authority' with 'responsible entity' in the High and Severe VSLs for Requirement R4. Also, replace 'the' with 'its' when referring to the Operating Plan or Reliability Coordinator.R5 - We suggest rewording the High and Severe VSLs to read: High - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators

Organization	Yes or No	Question 3 Comment
		but did not notify them within 30 minutes from the time of receiving notification. Severe - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
DTE Electric	No	Comments: For R3 High VSL, the requirement as written does not specify notification within 90 days. Our suggested revision to R3 in response to question 1 corrects this issue.
ACES Standards Collaborators	No	(1) We recommend adding a Lower VSL table for Requirement R1. There may be several factors, such as late annual reviews (one to three months late) that could result in a lower VSL. (2) For Requirement R4, we recommend adding a Lower and Moderate VSL. Failing to make updates by the RC deadline by a short time (one to thirty days) could be a Lower or Moderate VSL.(3) For Requirement R5, the Severe VSL requires notification of “impacted” RCs, BAs, and TOPs but the requirement states “adjacent” RCs, BAs, and TOPs. Which entities are required to be notified, impacted or adjacent?
ISO/RTO Council Standards Review Committee (SRC)	No	The SRC has the following concerns regarding the VSLs/VRFs:a. The SRC agrees with most of the assigned VRFs and VSLs, but have the following concerns:i. The VRF for Requirement R3 should be medium as it is an administrative requirement.b. There lacks a clear demarcation between the HIGH and SEVERE VSLs for Requirement R5. In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? Clarification is needed. Accordingly, the SRC suggests that the SDT consider making the VSLs for R5 fully staggered, which would include LOWER, MEDIUM, HIGH and SEVERE VSLs. For example, the LOWER VSL being up to 10 minutes late in notifying others, MEDIUM

Organization	Yes or No	Question 3 Comment
		VSL being up to 20 minutes late, HIGH being up to 30 minutes late and SEVERE being more than 30 minutes late.
Independent Electricity System Operator	No	We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5.In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
Kansas City Power and Light	No	R1 - Change the Moderate VSL to state ‘...to mitigate operating Emergencies in its Transmission Operator Area...’ to be consistent with the requirement and the other VSLs for this requirement. Change ‘...the Reliability Coordinator.’ in the High VSL to ‘...its Reliability Coordinator.’R2 - Add the phrase ‘within its Balancing Authority Area’ following the usage of ‘Emergencies’ in the Moderate, High and Severe VSLs for Requirement R2.R3- Insert ‘-calendar’ following ‘30’ in the High VSL.R4 - Replace ‘Transmission Operator and Balancing Authority’ with ‘responsible entity’ in the High and Severe VSLs for Requirement R4. Also, replace ‘the’ with ‘its’ when referring to the Operating Plan or Reliability Coordinator.R5 - We suggest rewording the High and Severe VSLs to read: High - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within it Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators

Organization	Yes or No	Question 3 Comment
		but did not notify them within 30 minutes from the time of receiving notification. Severe - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
Exelon Companies	No	The VSL for R1 does not identify any of the sub requiirments in the standard, the VSL's lack specificity.
Texas Reliability Entity	No	Requirement R5 VSL language does not match the updated Requirement R5 language. Texas RE recommends that the VSL language be updated to reflect the revised R5 language. The term "impacted" should be removed and replaced with "neighboring." The R5 VSL update would read as follows: "The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other [impacted] Reliability Coordinators, Balancing Authorities and Transmission Operators [in its Reliability Coordinator Area, and neighboring Reliability Coordinators] but did not notify within 30 minutes from the time of receiving notification."
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	Please see question 1.
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	Yes	

Organization	Yes or No	Question 3 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	
Hydro-Quebec TransEnergie	Yes	
We Energies	Yes	
Salt River Project	Yes	
Manitoba Hydro	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

4. Are there any other concerns with the proposed standard that have not been covered by previous questions and comments? If so, please provide your feedback to the EOP SDT

Summary Consideration: Thank you for your comments.

SPP and Kansas City Power and Light provided comments to the revised defined term Energy Emergency and asked for clarification of Load obligation and whether this includes Contingency Reserves. The EOP SDT's intent was not for the Load obligation to include Contingency Reserves.

The Technical Justification has been updated to the current revisions of EOP-011-1.

First Energy and ISO New England Inc. suggested revision to Requirement R1 Part 1.2. and Requirement R2 Part 2.2. to delete the words "prepare for and" to prevent misinterpretation that would expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC "Emergency" definitions, but it could lead to an "Emergency" state. The EOP SDT drafted the language with the intent that preparing for Emergency conditions is a necessary part of mitigating operating Emergencies, therefore, the drafting team elected to retain the language as drafted.

DTE Electric commented on time periods be defined for Requirements R3 and R4. The EOP SDT maintains that Requirement R3 provides a 30-day time period; and that the time requirement in Requirement R4 is appropriately addressed by providing a mechanism by which the Reliability Coordinator is provided the operational flexibility necessary to account for variances in regional considerations.

Dominion commented: "Compliance section C, Compliance Monitoring and Assessment Processes,1.3; in other Standards Under Development (IRO-002-4 and others in Project 2014-03) Dominion noticed these items under this section have been removed and the below statement has been added to this section 'As defined in the NERC Rules of Procedure;' Compliance Monitoring and Assessment Processes' refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.' If this is the direction NERC is headed, then EOP-011-1 needs to have Section 1.3 updated with the above statement for consistency." The EOP SDT agrees with Dominion's comment and has implemented this revision to Compliance Section C, Compliance Monitoring and Assessment Processes.

Seattle City Light commented that adding an explicit statement in EOP-011-1 that an entity registered as both a Transmission Operator and a Balancing Authority not be required to maintain two separate Operating Plans to demonstrate compliance with Requirements R1 and R2; that a single plan can be used to show compliance with these two requirements. The EOP SDT drafted the requirement with the intent that the Risk-based approach enables an entity to define the most appropriate methodology for plans for their entity. Rather than adding an explicit statement in the standard, however, the EOP SDT suggested clarifying language to be added in the RSAW.

Manitoba Hydro commented that the term “curtailable Load” is redundant in Requirement R2 Part 2.2.7., as it is inclusive in the definition of “Interruptible Load” in the NERC Glossary of Terms. The EOP SDT retained the term “curtailable Load” in the requirement part.

ACES Standards Collaborators commented about the inclusion of LSE in the proposed revised definition of Energy Emergency. SRC also commented on the revised definition of Energy Emergency and provided language revision suggestions. The EOP SDT retained the language as drafted and maintains that revisions necessitated by future changes will be addressed appropriately when they arise. The drafting team has made no revisions to the proposed revision of the defined term Energy Emergency.

BPA requested clarification of Requirement R5 methodology. The EOP SDT drafted the requirement with the intent that, under Risk-based approach, an entity is able to define the most appropriate electronic communications, or equivalent evidence for their entity.

Hydro-Quebec provided comments for clarification to Requirement R1 Parts. The EOP SDT drafted the language with the intention that the TOP would notify the RC of current and projected conditions. In addition, the EOP SDT drafted the language for consistency with the other Parts of Requirement R2 with the intent that the process to prepare for and mitigate Emergencies includes requests for redispatch of generation.

Additionally, Hydro-Quebec suggested that a Reliability Coordinator may have numerous Balancing Authorities and Transmission Operators in its Reliability Coordinator Area who are not necessarily affected by an emergency declared by one of them, and suggested using the term “impacted entities.” The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Hydro-Quebec commented that there is no specific VSL if the Reliability Coordinator does not review the plans. The EOP SDT drafted language for the VSLs “identified a reliability risk” which would take place during a review of the plans. When reviewing the Operating Plan(s), the Reliability Coordinator is looking for deficiencies, inconsistencies, or conflicts between submitted plans that would cause further degradation to the BES during Emergency conditions. The EOP SDT believes that the VSLs are appropriate as written.

A comment was received stating that EOP-011-1 is not specific on which Operating Plan(s) the proposed standard addresses. The drafting team specifies in the Purpose statement “Operating Plan(s) to mitigate operating Emergencies.” In addition, Requirements R1 and R2 provide details regarding what should be included in the Operating Plan(s).

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
Northeast Power Coordinating Council	No	
MRO NERC Standards Review Forum	No	
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	
PPL NERC Registered Affiliates	No	
DTE Electric	No	Due to the lack of time being defined in Requirements 3 & 4, we are voting negative for this ballot period.
Duke Energy	No	
Peak Reliability	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	
Idaho Power	No	
Tacoma Power	No	
We Energies	No	
Salt River Project	No	
Exelon Companies	No	
South Carolina Electric & Gas	No	
Texas Reliability Entity	No	
Tri-State Generation and Transmission Association, Inc.	No	
Dominion	Yes	Compliance section C, Compliance Monitoring and Assessment Processes,1.3; in other Standards Under Development (IRO-002-4 and others in Project 2014-03) Dominion has noticed these items under this section have been removed and the below statement has been added to this section "As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard."If this is the direction NERC is headed, then EOP-011-1 needs to have Section 1.3 updated with the above statement for consistency.
Seattle City Light	Yes	Seattle City Light supports the proposed draft but asks for an explicit statement in the Standard that an entity registered as both a TOP and a BA is not required to maintain

Organization	Yes or No	Question 4 Comment
		two separate Operating Plans to demonstrate compliance with R1 (TOP plan) and R2 (BA plan), and that a single plan can be compliant so long as it address the required plan elements for both functions.
FirstEnergycorp	Yes	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, "Processes to prepare for and mitigate Emergencies" is inconsistent with the Purpose of the Standard, that is, "...to mitigate operating Emergencies." The words "prepare for and" should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC "Emergency" definitions, but it could lead to an "Emergency" state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an "Emergency" state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the "prepare for" language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached.In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows:"It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to mitigate those Emergency conditions. From a compliance standpoint, the EOP SDT was not looking at abnormal conditions that could lead to an Emergency state." Thus, it is clear that the words "prepare for and" should be deleted as described above because they are inconsistent with the standard's stated purpose and the EOP SDT's intention in developing EOP-011-1.
SPP Standards Review Group	Yes	Regarding the change of 'energy obligation' to 'Load obligation' in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency

Organization	Yes or No	Question 4 Comment
		Reserves? According to the definition of Load in the NERC Glossary, it shouldn't. If it doesn't, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency.We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.The Technical Justification document has not been updated to match the currently posted draft standard.
ACES Standards Collaborators	Yes	(1) We question the inclusion of LSE in proposed definition of Energy Emergency. The Risk Based Registration (RBR) project is proposing to remove the LSE function. If the LSE is retired, does this proposed definition logically make sense? The definition should be revised to remove the LSE and focus the activities on the Balancing Authority. Furthermore, unless the BA is also in an EEA it is highly unlikely for an individual LSE in the Host BA to be in an EEA as this implies there is excess energy available in the Host BA. The LSE should not be an applicable entity for EOP-011-1.(2) Thank you for the opportunity to comment.
ISO/RTO Council Standards Review Committee (SRC)	Yes	While the SRC agrees that entities need to be forecasting conditions and taking actions to address deficiencies prior to real-time, the SRC disagrees with the revisions made to the term "Energy Emergency". The posting indicates that revisions were made solely to recognize that Load-Serving Entities are not the only entities that may declare an Energy Emergency. However, additional revisions appear to bring forecasted conditions within the definition of "Energy Emergency". The SRC assesses that, while the forecasting of potential deficiency conditions is important, use of the term "Energy Emergency" should be reserved for those conditions where an entity is truly "energy deficient" regarding serving its Load obligations, i.e., at an Energy Emergency Alert level 2 or above. The SRC proposes the following revisions be made to the definition of Energy Emergency:Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide sufficient energy to meet its Load obligations.

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Bonneville Power Administration	Yes	BPA requests verification/clarification of R5 notification methodology: Will WECCNet suffice as "electronic communications, or equivalent evidence"? BPA believes it would be unrealistic for the RC to all of the BA/TOPs in its footprint (50-100 or more) within 30 minutes by any any other manner.
Kansas City Power and Light	Yes	Regarding the change of 'energy obligation' to 'Load obligation' in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency Reserves? According to the definition of Load in the NERC Glossary, it shouldn't. If it doesn't, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency.We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.The Technical Justification document has not been updated to match the currently posted draft standard.
Hydro-Quebec TransEnergie	Yes	R1 - Paragraphs 1.2.1 and 1.2.4 are ambiguousRegarding 1.2.1, two possible interpretationsa) TOP should notify RC of current and projected conditions. 1.2.1. Notification to the Reliability Coordinator of current and projected conditions, when experiencing an operating Emergency;b) However, If the purpose is for TOP to notify RC to actually include the current and projected conditions, then the following question is to include them in what? In that case, there is a part of the sentence that is missing.Regarding 1.2.4, the phrasing is ambiguous: 2 possible interpretations and rephrasings depending on if the purpose of the process is to redispatch or to request redispatch.a) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4. Redispatch of generationb) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4 Request for redispatch of generationR2- Same comments apply to 2.2.1 as those made regarding 1.2.1R3 - Table of Compliance ElementsThere is no VSL if the RC does not review the Plan. We suggest that this be added to the Severe VSL .R5- A RC may have numerous BA and TOP in its RC area who are not necessarily affected by an emergency declared by one of them. We suggest the use of the same terminology as that used in the Table of Compliance section of the standard which

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		refers to impacted entities. Therefore, R5 would read:Each RC that receives an Emergency notification from a TOP or BA shall notify, within 30 minutes from the time of receiving notification, other impacted or potentially impacted BA and TOP in its RC Area, and neighboring RCs,Same comment applies to M5.Attachment 1, section 3.3.1.: there is a typographical error.The energy deficient BA, upon notification from its RC of the situation, it will immediately take whatever actions are necessary (...)
Manitoba Hydro	Yes	Requirement R2.2.7 "Use of Interruptible Load, curtailable Load and demand response." The term curtailable Load is redundant as it is already included in the definition of" Interruptible Load in the "Glossary of Terms Used in NERC Reliability Standards" as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment."
ISO New England Inc.	Yes	The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, "Processes to prepare for and mitigate Emergencies" is inconsistent with the Purpose of the Standard, that is, "...to mitigate operating Emergencies." The words "prepare for and" should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC "Emergency" definitions, but it could lead to an "Emergency" state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an "Emergency" state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the "prepare for" language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached.In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows:"It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to

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Additional Comments:

LCRA
Dixie Wells

EOP-011-1 is not specific enough on which operating plans it addresses.

END OF REPORT