

Consideration of Comments on Project 2010-12 — Order 693 Directives

The Order 693 Directives Drafting Team thanks all commenters who submitted comments on the current drafts of BAL-002-1, BAL-005-1, EOP-001-2, EOP-002-3, EOP-003-2, EOP-004-2, FAC-002-1, MOD-017-1, MOD-019-1, MOD-020-1, MOD-021-2, PRC-004-2, and VAR-001-2. These standards were posted for a 15-day public comment period from June 18, 2010 through July 2, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 36 sets of comments, including comments from more than 130 different people from over 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The work for this project has been posted on the following site:

http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.html

Stakeholder comments were used to determine whether each proposed modification should move forward to a second ballot and to determine, if the modification was supported by stakeholders, whether additional modifications would improve the proposed language. The following table summarizes the disposition of the proposed modifications.

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
BAL-002-1	P330 P335 P1232	No – the proposed modifications were removed from the standard	
	P321	Yes	Modified R4.2 and R6.2
BAL-005-1	P404 P415 P420	No – the proposed modifications were removed from the standard	
EOP-001-2	P571	No – the proposed modifications were removed from the standard	
EOP-002-3	P573	No – the proposed modifications were removed from the standard	
	P577	No – no modifications were proposed; stakeholders agreed the directive was addressed in IRO-006-4	
	P582	Yes	Modified M5
EOP-003-2	P601 P603	No – the proposed modifications were removed from the standard	
EOP-004-2	P612 P615	No – the proposed modifications were removed from the standard	
FAC-002-1	P693	Yes	No modifications
MOD-017-1	P1249 P1250 P1251 P1252 P1255	No – the proposed modifications were removed from the standard	
MOD-019-1	P1276	No – the proposed modifications were removed	

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
	P1277	from the standard	
MOD-020-1	P1287	No – the proposed modifications were removed from the standard	
MOD-021-1	P1300	Yes	No modifications
PRC-004-2	P1469	Partial – changes to expand applicability to include LSEs and TOPs were removed; Changes to replace the RRO with RE were retained	Modified M1, M2, M3
VAR-001-2	P1858 P1879	Yes	Modified R2, R5, R9

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

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

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The Industry Segments are:

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment											
				1	2	3	4	5	6	7	8	9	10		
1.	Group	Guy Zito	Northeast Power Coordinating Council												x
		Additional Member	Additional Organization	Region	Segment Selection										
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10											
2.	Gregory Campoli	New York Independent System Operator	NPCC	2											
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2											
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1											
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1											
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10											
7.	Dean Ellis	Dynegy Generation	NPCC	5											
8.	Ben Eng	New York Power Authority	NPCC	4											
9.	Brian Evans-Mongeon	Utility Services	NPCC	8											
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3											
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5											
12.	Kathleen Goodman	ISO - New England	NPCC	2											
13.	Chantel Haswell	FPL Group, Inc.	NPCC	5											
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1											
15.	Michael R. Lombardi	Northeast Utilities	NPCC	1											

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	Commenter	Organization	Industry Segment																	
			1	2	3	4	5	6	7	8	9	10								
16.	Randy MacDonald	New Brunswick System Operator	NPCC	2																
17.	Bruce Metruck	New York Power Authority	NPCC	6																
18.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10																
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1																
20.	Michael Schiavone	National Grid	NPCC	1																
2.	Group	Jim Case	SERC OC Standards Review Group	x			x													
	Additional Member	Additional Organization	Region	Segment Selection																
1.	Gerald Beckerle	Ameren	SERC	1, 3																
2.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 3, 5																
3.	Rene' Free	SCPSA	SERC	1, 3, 5, 9																
4.	Vicky Budreau	SCPSA	SERC	1, 3, 5, 9																
5.	Glenn Stephens	SCPSA	SERC	1, 3, 5, 9																
6.	Wayne Mitchell	Entergy	SERC	1, 3																
7.	Melinda Montgomery	Entergy	SERC	1, 3																
8.	Jennifer Weber	TVA	SERC	1, 3, 5, 9																
9.	Larry Akens	TVA	SERC	1, 3, 5, 9																
10.	Rick Myers	EEL	SERC	1, 5																
11.	Andy Burch	EEL	SERC	1, 5																
12.	Gary Hutson	SMEPA	SERC	1, 3, 5																
13.	Eugene Warnecke	Ameren	SERC	1, 3																
14.	Paul Turner	GASOC	SERC	1, 3, 5																
15.	Louis Slade	Dominion VP	SERC	1, 3																
16.	Robert Thomasson	BREC	SERC	1, 3, 5, 9																
17.	Timmy LeJeune	La Generating	SERC	1, 3, 5																
18.	Derek Rahn	E.ON.US	SERC	1, 3, 5																
19.	Richard Chapman	OMU	SERC	1, 3, 5																
20.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9																
21.	Randy Castello	Mississippi Power	SERC	1, 3, 5																
22.	John Troha	SERC	SERC	10																

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		Commenter	Organization	Industry Segment											
				1	2	3	4	5	6	7	8	9	10		
3.	Group	Carol Gerou	NERC Standards Review Subcommittee												x
	Additional Member	Additional Organization	Region	Segment Selection											
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6											
2.	Chuck Lawrence	American Transmission Company	MRO	1											
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6											
4.	Jason Marshall	Midwest ISO Inc.	MRO	2											
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6											
6.	Ken Goldsmith	Alliant Energy	MRO	4											
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6											
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6											
9.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6											
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6											
11.	Scott Nickels	Rochester Public Utilities	MRO	4											
12.	Terry Harbour	MidAmerican Energy Company	MRO	6, 1, 3, 5											
4.	Group	Andy Tillery	Southern Company Transmission	x		x									
	Additional Member	Additional Organization	Region	Segment Selection											
1.	JT Wood		SERC	1											
2.	SERC OC	SERC	SERC												
3.	Marc Butts		SERC	1											
4.	Bill Schultz		SERC	3											
5.	Steve Carter		SERC	3											
6.	Chris Wilson		SERC	1											
7.	Phil Winston		SERC	3											
5.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	x		x		x	x						
	Additional Member	Additional Organization	Region	Segment Selection											
1.	Mark Godfrey	Delmarva Power & Light	RFC	1											
2.	Rob Reuter	Potomac Electric Power Co.	RFC	3											
3.	Michael mayer	Delmarva Power & Light	RFC	3											

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	Commenter	Organization	Industry Segment																	
			1	2	3	4	5	6	7	8	9	10								
4.	Jim Petrella	Atlantic City Electric	RFC	3																
5.	Kara Dundas	Conectiv Energy Supply, Inc	RFC	5																
6.	James Newton	Pepco Energy Services	RFC	6																
6.	Group	Jason L. Marshall				x														
Additional Member Additional Organization Region Segment Selection																				
1.	Jim Cyrulewski	JDRJC Associates, LLC	RFC	8																
2.	Barb Kedrowski	We Energies	RFC	3, 4, 5																
7.	Group	Louis Slade				x		x		x	x									
Additional Member Additional Organization Region Segment Selection																				
1.	Michael Gildea		SERC	3																
2.	Mike Garton		NPCC	5																
3.	John Loftis		SERC	1																
4.	Louis Slade		RFC	6																
8.	Group	Frank Gaffney				x		x		x	x									
Additional Member Additional Organization Region Segment Selection																				
1.	Timothy Beyrle	Utilities Commission of New Smyrna Beach	FRCC	4																
2.	Greg Woessner	Kissimmee Utility Authority																		
3.	James Howard	Lakeland Electric																		
4.	Lynne Mila	City of Clewiston																		
5.	Joe Stonecipher	Beaches Energy Services																		
6.	Cairo Vanegas	Fort Pierce Utilities Authority																		
9.	Group	Terry Blackwell				x														x
Additional Member Additional Organization Region Segment Selection																				
1.	Tom Abrams		SERC	1, 9																
2.	Glenn Stephens		SERC	1, 9																
3.	Rene' Free		SERC	1, 9																
4.	Vicky Budreau		SERC	1, 9																
5.	Jim Peterson		SERC	1, 9																

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	Commenter	Organization	Industry Segment																	
			1	2	3	4	5	6	7	8	9	10								
6.	Wayne Ahl	SERC	1, 9																	
10.	Group	Bob Canada and Brian Evans-Mongeon	Disturbance and Sabotage Reporting Drafting Team	x	x	x		x												
	Additional Member	Additional Organization	Region	Segment Selection																
	1. James Hartman	ERCOT	ERCOT	2																
	2. Bob Canada	SCS	SERC	1, 3, 5																
	3. Michele Draxton	Constellation Energy	RFC	5																
	4. Chris Boucher	BC Hydro	WECC	1																
	5. Tom Moleski	PJM	RFC	2																
	6. Joe Depoorter	Madison Gas & Electric	MRO	1																
	7. Brian Evans-Mongeon	Utility Services	NA - Not Applicable	NA																
	8. Brian Harrell	SERC	SERC	10																
11.	Group	Ben Li	IRC Standards Review Committee		x															
	Additional Member	Additional Organization	Region	Segment Selection																
	1. Charles Yeung	SPP	SPP	2																
	2. Bill Phillips	MISO	MRO	2																
	3. Steve Myers	ERCOT	ERCOT	2																
	4. James Castle	NYISO	NPCC	2																
	5. Patrick Brown	PJM	RFC	2																
	6. Mark Thompson	AESO	WECC	2																
	7. Matt Goldberg	ISO-NE	NPCC	2																
	8. Greg Van Pelt	CAISO	WECC	2																
12.	Group	Michael Gammon	Kansas City Power & Light	x		x		x	x											
	Additional Member	Additional Organization	Region	Segment Selection																
	1. Jennifer Flandermeyer	KCPL	SPP	1, 3, 5, 6																
	2. Jim Useldinger	KCPL	SPP	1, 3, 5, 6																
	3. Harold Wyble	KCPL	SPP	1, 3, 5, 6																
	4. Denney Fales	KCPL	SPP	1, 3, 5, 6																

Consideration of Comments on Project 2010-12 — Order 693 Directives

	Commenter	Organization	Industry Segment													
			1	2	3	4	5	6	7	8	9	10				
5.	Rod Lewis	KCPL	SPP	1, 3, 5, 6												
6.	Tom Saitta	KCPL	SPP	1, 3, 5, 6												
7.	Tim Hinken	KCPL	SPP	1, 3, 5, 6												
13.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company		x		x		x	x						
14.	Individual	Steve Rueckert	Western Electricity Coordinating Council													x
15.	Individual	Brent ingebrightson	E.ON U.S.		x		x		x	x						
16.	Individual	Sandra Shaffer	PacifiCorp		x		x		x	x						
17.	Individual	Dan Roethemeyer	Dynegy Inc.						x							
18.	Individual	Steve Alexanderson	Central Lincoln				x	x								
19.	Individual	Terry Vogel	central Maine Power Company		x											
20.	Individual	Scott Barfield-McGinnis	Georgia System Operations Corporation				x	x								
21.	Individual	Jonathan Appelbaum	United Illuminating Company		x											
22.	Individual	Jeff Nelson	Springfield Utility Board				x									
23.	Individual	Bob Thomas	Illinois Municipal Electric Agency					x								
24.	Individual	Ed Davis	Entergy Services		x		x		x	x						
25.	Individual	Michael Ibold	Xcel Energy				x									
26.	Individual	Joylyn Faust	Consumers Energy Company				x	x	x							
27.	Individual	Kirit Shah	Ameren		x		x		x	x						
28.	Individual	Dan Rochester	IESO			x										
29.	Individual	CJ Ingersoll	CECD	N/A												
30.	Individual	Thad Ness	American Electric Power		x		x		x	x						
31.	Individual	David	SDG&E		x											
32.	Individual	Scott Berry	Indiana Municipal Power Agency					x								

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
33.	Individual	Laura Zotter	ERCOT ISO		x									
34.	Individual	Martin Bauer	US Bureau of Reclamation					x						
35.	Individual	Saurabh Saksena	National Grid	x		x								
36.	Individual	Terri Pyle	Oklahoma Municipal Power Authority				x							

1. Do you believe the changes made in response to the directive(s) contained in Paragraph 321 of Order No. 693 are both valid and address the directive(s)?

321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	BAL-002-1	Modified Section B Requirement R4.2 and R6.2.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	BAL-002-1	Modified Section D 1 and 1.1

Organization	Question 1
CECD	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Santee Cooper	No
SERC OC Standards Review Group	No

Organization	Question 1
US Bureau of Reclamation	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
Georgia System Operations Corporation	Yes
IESO	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

2. Do you believe the changes made in response to the directive(s) contained in Paragraph 330 of Order No. 693 are both valid and address the directive(s)?

330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	BAL-002-1	Modified Section B Requirement R1. Modified definitions of "Operating Reserve - Spinning," and "Operating Reserve – Supplemental." Deleted definition of "Spinning Reserve."
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Organization	Question 2
Ameren	No
Arizona Public Service Company	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Pepco Holdings, Inc. - Affiliates	No

Organization	Question 2
Santee Cooper	No
Southern Company Transmission	No
Xcel Energy	No
American Electric Power	Yes
CECD	Yes
Dominion	Yes
Entergy Services	Yes
IESO	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
SERC OC Standards Review Group	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes

3. Do you believe the changes made in response to the directive(s) contained in Paragraph 335 of Order No. 693 are both valid and address the directive(s)?

335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	BAL-002-1	Modified definition of "Demand Side Management."
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Organization	Question 3
Ameren	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Santee Cooper	No

Organization	Question 3
SERC OC Standards Review Group	No
Southern Company Transmission	No
Springfield Utility Board	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
United Illuminating Company	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes

4. Do you believe the changes made in response to the directive(s) contained in Paragraph 1232 of Order No. 693 are both valid and address the directive(s)?

1232	We approve the ERO’s definition in the glossary of DSM as “all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use.” Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM “any other entities” that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	BAL-002-1	Modified definition of “Demand Side Management.”
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Organization	Yes or No
Xcel Energy	No
Kansas City Power & Light	No
E.ON U.S.	No
Springfield Utility Board	No
Entergy Services	No
SERC OC Standards Review Group	No
Santee Cooper	No
Southern Company Transmission	No
Ameren	No
Northeast Power Coordinating Council	No
ERCOT ISO	No

Organization	Yes or No
IESO	No
Georgia System Operations Corporation	No
Midwest ISO Standards Collaborators	No
American Electric Power	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Arizona Public Service Company	Yes
Oklahoma Municipal Power Authority	Yes
Indiana Municipal Power Agency	Yes
CECD	Yes
US Bureau of Reclamation	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Dominion	Yes

Comments on the BAL-002 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received on these modifications and determined that addressing the directives in paragraphs 330, 335, and 1232 will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will not be responded to individually at this time. However, they will be retained for future consideration.

Specific to the proposed changes to address Paragraph 321, some commenters disagreed with the replacement of Regional Reliability Organization with Regional Entity in Section D1 and D1.1 on the basis that Regional Entity is not defined in the Functional Model. Version 5 Reliability Functional Model Technical Document, Ch. 15, indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." The Response Team therefore does not find using the term Reliability Entity inappropriate.

Several commenters suggested that instead of replacing "NERC Operating Committee" with "ERO," the standard could be improved in an alternate fashion simply by removing the provisions for unilateral adjustment of these time periods by any group or entity. The Response Team agreed and removed the last two sentences of R4.2 and R6.2, which now read as follows:

R4.2 The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R6.2 The default Contingency Reserve Restoration Period is 90 minutes.

Organization	Question 4 Comment
IRC Standards Review Committee	Taken in isolation the concept of changing NERC OC to ERO would be reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the two requirements. Two requirements that require significant review and change. The SAR requestor misses a key point in R4.2 and R6.2 and that is the fact that the requirement itself is about making changes to the DCS recovery period itself. Who makes the change is secondary to the fact that the changes are being allowed at any time without any clarity about implementation and compliance. In a pre-mandatory environment, such changes could be made as needed. However, both R4.2 and R6.2 now need to be reconsidered regarding the implication of "approving" a simplistic change to what may be an inappropriate standard. The Industry must identify such details as whether or not changes are made "annually" or "as needed". What does it mean to "better suit the needs of an Interconnection"? Compliance entities need guidance about how to decide compliance. Do changes resulting from the ERO analysis occur on day-one that the change is made, or is there an implementation grace period - all this needs to be formally explained in the standard. Technically, the two BAL-002 requirements 4.2 and 6.2 that are in effect today, as well as the revised proposed actually introduce the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. An alternative solution (one that meets the Commission mandate that allows the ERO to offer and equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be

Organization	Question 4 Comment
	<p>modified outside the standards development process.</p> <p>Paragraph 321 Taken in isolation the concept of changing Regional Reliability Organization to Regional Entity would be reasonable. But does such a trivial change warrant expedited (i.e. Urgent Action) treatment by bypassing the FERC-approved Reliability Standards Development Process? Paragraph 330 Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to provide contingency reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the requirement itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific types of resource or technology that may or may not be used to fulfill a requirement. We believe this results in a “HOW” to meet a requirement instead of “WHAT” to meet the requirements and, have, in the past opposed such specifications within the Standards. The ISO/RTOs currently allow DSM to compete with generation as a resource to supply contingency reserves. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. We think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants).</p> <p>Paragraph 335 We disagree with striking the word ‘load’ from BAL-001 R1. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes.</p> <p>Paragraph 1232 The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose (i.e. providing one or more services...). Paragraph 1232 directed the ERO to expand the original DSM definition adding the phrase: “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The SAR-proposed definition - in addition to including the Order 693 wording - proposes to limit the scope of DSM within a specific type that is eligible for inclusion in being used as a reserve. While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the DSM definition would effectively exclude (as DSM) those demand side management resources that do not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics. Although FERC suggested the wording used in this proposal, the requestor is reminded that FERC has repeated stated that equally effective alternatives are appropriate. The words need to</p>

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	<p>be considered and vetted in light of all DSM initiatives. NERC has several DSM activities now in process. The reason for those activities is specifically because DSM (as an evolving technology) is not a well-defined universally accepted term. NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrase as “of the resources it is replacing” is inappropriate and incorrect. One could ask if it were better to state “of the resources it is competing with”. And will it always compete with generation, may it not “replace” other DSM products? In short, the proposed definition is not a good definition.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>Specific to the comment on changes regarding the Regional Entity, Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: “NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.” We do not find using the term Regional Entity inappropriate.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
<p>Kansas City Power & Light</p>	<p>Directives 330, 335, and 1232:In the definitions for “Operating Reserve - Spinning” and “Operating Reserve - Supplemental” the second bulleted item regarding Demand Side Management Resources should refer directly to “disturbance recovery period” instead of “time necessary to provide service”. In addition, it is not clear that Demand Side Management actions can qualify as spinning as the load response or other actions is not automatically responsive to system changes. As an example, one of the actions could be the use of independent distributed generation resources to offset system load which is typically not synchronized to the grid.</p>
<p>E.ON U.S.</p>	<p>E ON U.S. suggests striking the entire last sentence of R4.2 and R6.2. Changing of the disturbance recovery period and the restoration period and the standard should follow the Standard Development Process.Paragraphs 330 & 335 only address the use of DSM for contingency reserves, not “one or more services” E ON U.S. suggests the following edits:</p> <p>Demand-Side Management (DSM): Activities undertaken by end-use customers, Load-Serving Entities or their agents or representatives to change electrical demand, without violating Reliability Standards, in order to provide contingency reserves. In order to provide contingency reserve, DSM resources must maintain electrical response characteristics equivalent to or better than the contingency reserve providing generation resources being replaced.</p> <p>Operating Reserve - Spinning: The portion of Operating Reserve consisting of:</p> <ul style="list-style-type: none"> o Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or o Demand Side Management Resources or other devices with capability to adequately respond within the time necessary to provide the contingency reserve service; or o Load which is fully removed from the system within the Disturbance Recovery Period and remains removed from the system for the duration of the Disturbance Recovery Period following the contingency event. <p>Operating Reserve –</p>

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	<p>Supplemental: The portion of Operating Reserve consisting of:</p> <ul style="list-style-type: none"> o Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or o Demand Side Management Resources or other devices with capability to adequately respond within the time necessary to provide the contingency reserve service; or o Load which is fully removable from the system within the Disturbance Recovery Period and remains removed from the system for the duration of the Disturbance Recover Period following the contingency event. <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Springfield Utility Board	<p>Overall SUB supports the intent behind the change but rather than clarify dispatchable and non-dispatchable DSM, these two distinct DSM activities are attached to a very broad definition Demand Side Management and are left unclear. Plus, use of the universal term permeates many standards and creates unintentional consequences. Understanding that DSM permeates multiple standards, completely deleting the definition of DSM may not be practical. However, what may be practical is to add NEW definitions for "Dispatchable Demand Side Management" and "Non-Dispatchable Demand Side Management".</p> <p>SUB suggests that a better clarification would be to.</p> <ol style="list-style-type: none"> 1) Keep the existing definition of DSM as is. 2) Add a new definition of Non-Dispatchable Demand Side Management: "Non-Dispatchable Demand Side Management, NDSDM, is DSM that influences the amount of electricity used but does not provide for the ability to control the timing of the use to provide the one or more services traditionally provided by generation resources. NDSDM may influence timing of use, but not to provide transmission support services traditionally provided by the dispatch of generation resources " 3) Add a new definition of Dispatchable Demand Side Management: "Dispatchable Demand Side Management, DSDM, is DSM that influences the amount of electricity used and provides for the ability to control the timing of the use without violating Reliability Standards in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." 4) The proposed modification to the definition "Operating Reserves" currently refers to the term "Demand Side Management". "Demand Side Management" would be replaced with "Dispatchable Demand Side Management" 5) The proposed modification to the definition "Operating Reserve - Supplemental" currently refers to the term "Demand Side Management". "Demand Side Management" would be replaced with "Dispatchable Demand Side Management" 6)The proposed change to R1 add DSM "R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to

Organization	Question 4 Comment
	<p>respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, Demand Side Management (DSM), or coordinated adjustments to Interchange Schedules."Again, use of the term DSM in the context of BAL-005-1 is overly broad and new definitions (discussed earlier) should be used to clarify what DSM applies to BAL-005-1. Confusion leads to uncoordinated compliance activities and reduction in reliability.New R1 language: "R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, Dispatchable Demand Side Management (DDSM), or coordinated adjustments to Interchange Schedules."</p> <p>Response: Please see our response in the Summary Consideration.</p>
Entergy Services	<p>Paragraph 1232 - in the definition for DSM, we suggest the word "Load"; be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role."In order to do so, DSM Products must have the same response characteristics (but not necessarily mechanical or physical implementation) ofthe resources it is replacing."</p> <p>Response: Please see our response in the Summary Consideration.</p>
SERC OC Standards Review Group	<p>Paragraph 321 - "While modifications to BAL-002 may address FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. A superior alternative solution (which meets the Commission mandate that allows the ERO to offer an equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process.</p> <p>"Paragraph 1232 - in the definition for DSM, we suggest the word "Load; be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Santee Cooper	<p>Paragraph 321 - The last sentence of R4.2 and R6.2 should be deleted from the standard. Any changes to standards should follow the ANSI approved standards process. Paragraphs 330, 335, and 1232 - Any changes to NERC definitions should follow the ANSI approved standards process.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p>
Southern Company Transmission	<p>Paragraph 330 - We do not agree with modifying the definition Operating Reserve - Spinning or Operating Reserve - Supplemental. What is different about DSM in new bullet that the existing "load Fully removable..." bullet does not address. FERC has made clear recently through a March 18 order of their concern regarding declining frequency response in the Eastern Interconnection. Because Operating Reserve - Spinning has an implied obligation to include frequency responsive generation, we believe that the inclusion of DSM as written</p>

Organization	Question 4 Comment
	<p>could further reduce frequency response. While some DSM may be frequency responsive, a significant portion may not be. At the very least, this demonstrates this is not low hanging fruit and should be referred to a drafting team. Additionally, we believe the purpose of the BAL-002 standard is to set contingency reserve obligations and is not an appropriate place to modify these definitions. Not sure why Demand Side Management is added to the list in BAL-002, R1 when “Controllable load resources” already existed. The difference is not clear and if it is based on the revised description of Demand Side Management will be problematic because the new definition will not be universally accepted. We disagree with striking load. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM.</p> <p>Paragraph 335 - Unclear how proposed words on definition accomplish FERC’s desire to have them treated comparable. What does the last sentence mean...”response characteristics”. All comments and changes ignore the fact that controllable loads are done so under the tariffs and contracts in place with the load not simply the fact that they are loads</p> <p>Paragraph 1232 - In the definition for DSM, we suggest the word “Load” be replaced with “DSM Products”. In the future, loads may not be the only Demand side Product capable of assuming this role.</p> <p>Response: Please see our response in the Summary Consideration.</p>
Ameren	<p>Q.2 Comments –</p> <ul style="list-style-type: none"> (a) In the definition of DSM, the parenthetical adds ambiguity. (b) Likewise, the implication that the DSM does not have to be controlled by an operator, means that DSM will not be comparable, and will lead to less reliability. (c) In both definitions of Operating Reserve, "control capability" should be followed by "at a dispatch center or control room". <p>Q.3 Comments - The existing definition of Contingency Reserve should be modified to state, "The portion of Operating Reserve used for responding to generation repairable Disturbance".</p> <p>Q.4 Comments –</p> <ul style="list-style-type: none"> (a) In R4.2, it should identify who (which group) at ERO; Enforcements, Standards, Event Analysis? (b) What is the appeal process? <p>Response: The Response Team has struck the second sentences of 4.2.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Northeast Power	<p>The proposed changes from Paragraph 321 should include the striking of the sentence in R4.2 “This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee ERO.” It is not enforceable or appropriate</p>

Organization	Question 4 Comment
Coordinating Council	<p>for a FERC approved requirement to be “adjustable” or waived. Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate, and do not agree with the proposed definition for DSM. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.</p> <p>Response: The Response Team has struck the second sentences of 4.2.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
ERCOT ISO	<p>These are not low-hanging fruit because these changes need to be in sync with other efforts underway as indicated in responses to Q2 - Q4 below.</p> <p>Q1 - The changes do not appropriately address the directives. We do not believe you can simply replace the NERC Operating Committee with the ERO in R4.2 and R6.2. We suggest simply deleting the last sentence of R4.2 and the last sentence of R6.2 because if the values of the requirements indeed need to change then the language would need to be revised through the standards development process.</p> <p>Q2 - The NERC Project 2007-05 Balancing Authority Controls is addressing reserves.</p> <p>Q3 and Q4 - There has been a large group working with both NERC (including the Functional Model Working Group) and NAESB on this topic. This is likely to be controversial and not low-hanging fruit. Additionally, ERCOT ISO recommends differentiating between Demand Side Management and Demand Response. NERC, via the Demand Response Data Task Force, provided solid differentiation between the two terms. See page 11 in the final report on the Demand Response Data Availability System (DADS): http://www.nerc.com/docs/pc/drdtf/DADS_Phase_I&II_Final_050510.pdf Under NERC’s definition, DSM includes Energy Efficiency as well as Demand Response. Especially in the context of Contingency Reserves, as proposed here, dispatchable DR should be the only type of resource capable of participating; it is not likely anyone would recommend extending it to Energy Efficiency.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
IESO	<p>We do not agree with the change of definition of DSM especially the latter part that says: “...in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” Further, the term Demand Side Manage Resource is used in the expanded definitions for Operating Reserve - Spinning and Operating Reserve - Supplemental.</p> <p>The word “Resource” should not be capitalized since it would imply a defined term.</p> <p>Paragraph 1232 directs the ERO to expand the definition to add “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The proposed definition added the above mentioned wording which limit the scope of DSM within a specific type that is eligible for inclusion in the list that can used as a reserve.</p>

Organization	Question 4 Comment
	<p>While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the definition exclude those demand that does not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics. We suggest the definition be truncated at “....without violating other Reliability Standard Requirement”.</p> <p>The part that says “...in order to provide the one or more.....resources it is replacing.” be removed, and whose intent to allow the use of DSM as a resource for contingency reserves, and that it be treated on a comparable basis and must meet similar technical requirements as other resources providing this service be covered by appropriate requirements.</p> <p>Response: Please see our response in the Summary Consideration.</p>
<p>Georgia System Operations Corporation</p>	<p>We do not object to the content or intent of the directive, or to the intent of the proposed changes, however we believe the current wording is confusing. Specifically:</p> <p>2a) It is not clear who “they” in the first sentence refers to. Grammatically it refers to end-use customers, LSEs, and their agents or representatives, but only end-use customers typically use electricity so we do not believe that was the intent. We suggest changing “the amount or timing of electricity they use” to “the amount or timing of electricity use”</p> <p>2b) We believe it would read better and be easier to understand if the phrase “without violating Reliability Standards” was changed to “in accordance with Reliability Standards” and moved to after the word “undertaken”.</p> <p>2c) The phrase “in order to provide the one or more services traditionally provided by generation resources” is vague. DSM addresses some of the same objectives as generation when viewed from a very high level, but does so in different ways. We recommend stating the objectives directly by replacing it with “to support voltage or frequency response or the balance of load and generation”. If you disagree with this change, change “provide the one or more services” to “provide the services”</p> <p>2d) We believe the last sentence is unnecessary because the same concept is conveyed in the definitions of spinning and supplemental reserves. If it is retained it should be reworded to improve its clarity. It starts with “In order to do so” but it is not clear exactly what that is referring to. It also says that the loads must have the same response characteristics of the resources it is replacing, but DSM is not defined as loads, but as activities. If it is retained we recommend replacing it with “to fall within the definition of DSM, an activity activities must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.”</p> <p>2e) Suggested re-wording of DSM: DSM - Programs operated in accordance with Reliability Standards to influence the amount or timing of electricity use in order to balance demand and resources or support frequency response. To fall within the definition of DSM, a program must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.</p> <p>2f) We recommend the second bullet of the definition of Spinning and Supplemental Reserves be changed to: Demand Side Management Resources with the capability to adequately respond within the time necessary to provide the service; or</p>

Organization	Question 4 Comment
	<p>2h) We recommend the third bullet of the definition of Spinning and Supplemental Reserves be deleted because anything covered by the third bullet would also be covered by the second.</p> <p>2i) In BAL 002 R1 the term “controllable load resource” was changed to “controllable resource” We do not understand the intended meaning of controllable resources and it is not a defined term. We believe that a controllable resource would be either a form of generation or DSM which are already listed in R1; therefore we recommend that it be deleted.</p> <p>Response: Please see our response in the Summary Consideration.</p>
<p>Midwest ISO Standards Collaborators</p>	<p>While modifications to BAL-002 may address FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. A superior alternative solution (which meets the Commission mandate that allows the ERO to offer an equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process.</p> <p>Modifying sub-requirements R4.2 and R6.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified its course of action would be.</p> <p>While we are supportive of allowing DSM to compete with generation as a resource to supply contingency reserves, we do not believe the directives from paragraph 330, 335, and 1232 regarding modifying BAL-002 represents low hanging fruit. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has on many occasions stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. Unfortunately, we think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM.</p> <p>Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants). We do not agree with modifying the definition Operating Reserve - Spinning or Operating Reserve - Supplemental. FERC has made clear recently through a March 18 order of their concern regarding declining frequency response in the Eastern Interconnection. Because Operating Reserve - Spinning has an implied obligation to include frequency responsive generation, we believe that the inclusion of DSM as written could further reduce frequency response. While some DSM may be frequency responsive, a significant portion may not be. At the very least, this demonstrates this is not low hanging fruit and should be referred to a drafting team.</p>

Organization	Question 4 Comment
	<p>Additionally, we believe the purpose of the BAL-002 standard is to set contingency reserve obligations and is not an appropriate place to modify these definitions. BAL-001 R1 - We disagree with striking load. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Consumers Energy Company	<p>2. Establishing quantitative criteria for the Disturbance Recovery Period requires broadly based and in-depth analysis, which can be obtained only through full industry input. In R4.2 the change to allow the ERO to change the value is inappropriate.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2.</p>
Florida Municipal Power Agency	<p>For Paragraph 321, a better solution would simply be to strike the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee", by doing so, any change to the 15 minutes or 90 minutes would be done through the ERO as part of the stakeholder process, meeting the intent of the directive that the ERO ought to do it, while retaining the stakeholder process.</p> <p>For Paragraph 330, spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control. For Paragraph 335, spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Arizona Public Service Company	<p>In the change of definition of Spinning Reserve, AZPS is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify who has control. For Spinning Reserve, the control should be with the System Operator, as a quick response is necessary. For instance, an aggregator may offer demand management on a centralized basis using a control system under the control of the aggregator, but may require a phone call from the System Operator to activate. That may be too slow and not dependable enough for Spinning Reserve. AZPS</p>

Organization	Question 4 Comment
	<p>suggests using Direct Control Load Management instead of DSM for Spinning Reserves.</p> <p>Response: Please see our response in the Summary Consideration.</p>
Oklahoma Municipal Power Authority	<p>Paragraph 321: The proposed wording could bypass the stakeholder process. Request that the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee." The changes would still meet the intent of the directive while not removing from the stakeholder process.</p> <p>Paragraph 330, 335: Spinning reserve should include only Direct Control Load Management.</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
Indiana Municipal Power Agency	<p>Question 1 - IMPA understands the use of ERO and Regional Entity; however, the abbreviation ERO is not in the NERC functional model or in the NERC glossary of terms and the same is true for the term Regional Entity. If these terms are going to be used in NERC standards then they need to be defined by NERC in the functional model and/or the NERC glossary of terms.</p> <p>Question 2 and 3 - Demand Side Management encompasses many resources of which some can be directly controlled and some cannot. The resources that can be directly controlled by an operator should be included in the contingency reserves.</p> <p>Response: Specific to the comment on changes regarding the Regional Entity, Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." We do not find using the term Regional Entity inappropriate.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>
CECD	<p>Question 1. The change addresses the directive but is not appropriate. To support of the standards development process, a better modification is to delete the phrase, "approved by the NERC Operating Committee" rather than change the reference from NERC OC to the ERO in R4.2 and 6.2.</p> <p>Question 3. CECD suggests the following addition to the second sentence of the DSM definitions, which currently states "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." CECD would change the definition to state "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the generation resource that would traditionally provide the function being met with DSM."</p> <p>Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p> <p>With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.</p>

Organization	Question 4 Comment
US Bureau of Reclamation	<p>The process to modify these standards is not following the accept and approved process. The excuse that "FERC has expressed concern that industry and NERC have been less responsive than desired in providing a timely resolution to those directives." offers no urgent or compelling reason for this extraordinary step. It is suggested that NERC utilize the conventional standard modification process for the changes requested by FERC.</p> <p>R4.2, 6.2. The last sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the ERO." should be removed. Modification to the standards would require the standard approval process. To require that the ERO approve an analysis adds no improvement in reliability of the BES.</p> <p>Response: The Response Team is using a process that has been approved by the Standards Committee for this particular project.</p> <p>The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.</p>
Pepco Holdings, Inc. - Affiliates	<p>The term "within the Disturbance Recovery Period following the contingency event" should be used to describe Demand Side Management Resources.</p> <p>Response: Please see our response in the Summary Consideration.</p>
Dominion	<p>While we agree that the change in paragraph 335 meets FERC directives, we believe that the definition of the term Demand Side Management needs further clarity, in particular the sentence that reads "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." We suggest something similar to "A Demand-Side Management activity must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing."</p> <p>Paragraph 1232 - in the definition for DSM, we suggest the word "Load;" be replaced with "DSM Products". In the future, loads may not be the only Demand side Product capable of assuming this role.</p> <p>Response: Please see our response in the Summary Consideration.</p>

5. Do you believe the changes made in response to the directive(s) contained in Paragraph 404 of Order No. 693 are both valid and address the directive(s)?

404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	BAL-005-1	Modified title of standards to be “Automatic Resource Control.” Modified definition of “Automatic Generation Control.” Added definition of “Automatic Resource Control.” Modified definition of “Regulating Reserve.” Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.
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Organization	Question 5
Ameren	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Santee Cooper	No

Organization	Question 5
Southern Company Transmission	No
Springfield Utility Board	No
US Bureau of Reclamation	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
Dynergy Inc.	Yes
Entergy Services	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

Organization	Question 5
Xcel Energy	Yes

6. Do you believe the changes made in response to the directive(s) contained in Paragraph 415 of Order No. 693 are both valid and address the directive(s)?

415	<p>Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission’s proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO’s Work Plan.</p> <p>410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area.</p> <p>411. FirstEnergy states that Requirement R17 should include only “control center devices” instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term “check” in Requirement R17 needs to be clarified.</p>	BAL-005-1	<p>Modified Section B Requirement R17. Modified VSLs for R17. Deleted interpretations, as they have been incorporated into R17.</p>
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Organization	Question 6
Ameren	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No

Organization	Question 6
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Springfield Utility Board	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes

Organization	Question 6
Southern Company Transmission	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

7. Do you believe the changes made in response to the directive(s) contained in Paragraph 420 of Order No. 693 are both valid and address the directive(s)?

420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	BAL-005-1	Modified title of standards to be “Automatic Resource Control.” Modified definition of “Automatic Generation Control.” Added definition of “Automatic Resource Control.” Modified definition of “Regulating Reserve.” Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service	BAL-005-1	Modified Section B Requirement R5.

Organization	Question 7
Xcel Energy	No
IESO	No
Ameren	No
Georgia System Operations Corporation	No
Pepco Holdings, Inc. - Affiliates	No
E.ON U.S.	No
Florida Municipal Power Agency	No

Organization	Question 7
Northeast Power Coordinating Council	No
Santee Cooper	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No
US Bureau of Reclamation	No
Springfield Utility Board	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dynergy Inc.	Yes
Kansas City Power & Light	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes

Organization	Question 7
Southern Company Transmission	Yes
Oklahoma Municipal Power Authority	Yes
Consumers Energy Company	Yes
Indiana Municipal Power Agency	Yes

Comments on the BAL-005 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P404, P415, and P420 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Comment
<p>IRC Standards Review Committee</p>	<p>Paragraph 404</p> <ul style="list-style-type: none"> o The proposed changes exceed the Commission directive. The directive is to change the title not throughout the entire document, it was not to change the definition of AGC. o The requestor would have been more correct if the proposal were to change the title from Automatic Generation Control to something as simple as “Area Control Error” or “Balancing Control”. o As proposed, any automatic process used in balancing would come under this umbrella. For example, if a BA used UFLS resources to help maintain its ACE, then by this definition UFLS would be AGC. o The term AGC should be considered for removal. There is no one control system - indeed many if not all control systems have their unique characteristics. What the standard mandates is the calculation and use of Area Control Error (ACE). o AGC is a generic industry term for a control process and not specific to any one resource. It is a term used by vendors and academics and Control Theory books. Thus AGC programs do have meaning to those outside our standard process, and those who service our control programs. o Regarding the proposed conforming changes to the first sentence of the definition of regulating Reserve, we question the need for the second sentence in the definition. o The FERC mandate is that DSM explicitly be allowed to provide regulating reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the definition itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Paragraph 415 o Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process.

Organization	Comment
	<p>o The proposed change introduces an undefined term “common reference”.</p> <p>Paragraph 420R5 imposes transmission-based responsibilities on the BA. That is simply wrong. The BA must plan and operate within the transmission constraints imposed by its TOPs. The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase “...provide replacement Regulation Service.”</p>
ERCOT ISO	<p>Q5 - The proposed changes address the directive, but the definition of DSM may be problematic if it differs from that which the Demand Response Data Availability System (DADS) has been developing. This is likely to be controversial and not low-hanging fruit. Changing from AGC to ARC is more complicated than just a title change and could cause confusion with standards applicability to AGC. There are system differences in deploying generation and deploying demand side resources. Q6 - The BAL-005-0.1b, regulatory approved on 5/13/2009, has sufficiently addressed the directive.</p>
IESO	<p>(1) Wrt changes for directives in Paragraph 404, we agree with the proposed definition of ARC and the proposed conforming changes to the first sentence of the definition of Regulating Reserve. However, we question the need for the second sentence in the latter definition, although we do not find it unacceptable.</p> <p>(2) Wrt the changes for directive in Paragraph 415, R17 says “Verify against a common reference” however it gives no indication of what an appropriate common reference is. Does this mean an entity can calibrate and check its primary frequency device against its backup? We imagine not. Clarification on the intent of this requirement would be appreciated as “common reference” is vague.</p> <p>(3) For the first part of changes for directive in Paragraph 420 involving defining ARC, please see our comment in (1), above.</p> <p>(4) Wrt the latter part of directive in Paragraph 420, we do not think the proposed changes to R5 fully address the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT.</p>
Ameren	<p>(a) The new definition introduces an acronym (ARC) that is already used by FERC for Aggregate Retail Customer</p> <p>(b) The proposed ARC definition should modify "Balancing Authority's interchange..." to "Balancing Authority Area's interchange ...", since BA does not have a schedule rather a BAA does (e.g. one BA may operate multiple BAA).</p>

Organization	Comment
	<p>(c) In the Regulating Reserve definition add "to generation resources" between comparable and response in the last phrase.</p> <p>(d) In R5 - No regulating reserve should be on non-firm service (e) In R7, the team uses ARC but refers to generation.</p>
<p>Georgia System Operations Corporation</p>	<p>5a) We agree with the intent, but disagree with the wording. We believe that "controllable load resources" are included within DSM and thus the inclusion of both is unnecessary and confusing. If the language is retained we suggest that it be made consistent with BAL 002 (controllable load resources vs. controllable resources).</p> <p>We recommend:5b) Under Compliance 1.1 it refers to "their" Regional Entity. However, 1.1.1. refers to "the" Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.</p> <p>6) BAL005 R5 is grammatically incorrect. Also we suggest removing the non-firm transmission language as it doesn't add to the requirement. Stating it is no longer deliverable should suffice.</p> <p>7) Under Compliance 1.1 it refers to "their" Regional Entity. However, 1.1.1. refers to "the" Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.</p>
<p>Pepco Holdings, Inc. - Affiliates</p>	<p>A BA does not monitor transmission constraints. Other standards already require a BA to follow the directions of a TOP or RC. This change is not needed.</p>
<p>E.ON U.S.</p>	<p>AGC is a well established, recognized, and understood standard industry term that E ON U.S. believes should not be summarily revised. Additionally, the suggested ARC term is misleading as this standard is only about regulation/load following.</p> <p>E ON U.S. suggests the following edits: Automatic Regulating Control (ARC): Automatic adjustment of resources and/or load serving a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus Frequency Bias.</p> <p>In R 17 - strike the words "reporting or compliance" and "real-time error or" - the "ors" add unnecessary confusion to the requirement. Suggest revising to "R17. Each Balancing authority shall at least annually verify against a common reference the calibration of its frequency devices that provide input into the ACE equation."</p>
<p>Florida Municipal Power Agency</p>	<p>For paragraph 404, Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative.</p> <p>For Paragraph 420, Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative in the definition of Regulating Reserve.</p>

Organization	Comment
Northeast Power Coordinating Council	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. NERC should find an alternate method to address the Commissions’ concern rather than simply “renaming” a widely, industry accepted and understood definition and concept such as “AGC.”
Santee Cooper	Paragraph 404 and 420 - Any changes to NERC definitions should follow the ANSI approved standards process. Note for Paragraph 415 - Most frequency devices today receive their frequency from GPS satellites which derive their frequency from the National Bureau of Standards. Therefore, there is no need for devices to be calibrated.
Dominion	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, “nonfarm” should be “non-firm.”
Entergy Services	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be needed to assure reliability. The Balancing Authority receiving Regulation Service should be required to ensure that backup plans are in place to provide replacement Regulation Service should the service no longer be deliverable due to transmission constraints impacting the service, whether firm or non-firm. This change would meet the intent of the Commission directive, and improve reliability by ensuring backup plans exist.
SERC OC Standards Review Group	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, “nonfarm” should be “non-firm.”
Midwest ISO Standards Collaborators	The proposed changes actually exceed the Commission directive from paragraph 404. The change is only required to the title not throughout the entire document. Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process. Therefore, there is no need to short circuit the NERC standards development process to make changes that should be handled through the five year review of the standard for a directive that has already been met. Furthermore, the proposed changes to R17 actually contradicts the interpretation. Specifically, the interpretation was clear that the

Organization	Comment
	<p>devices that needed to be calibrated are those devices that feed ACE and time error calculations. The proposed changes include any device that provides frequency information to the operator through the clause "or frequency information to the operator". At a minimum, this clause needs to be struck.</p> <p>We disagree with the changes to R5. First, the existing R5 already considers transmission constraints implicitly by stating "shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service." "Transmission constraints" is just one of a litany of reasons that the supplying Balancing Authority may not be able to provide regulation service. Why should transmission constraints be singled out as a reason? Secondly, BAL-001-0.1a still applies to the receiving BA regardless. That is, the receiving BA still must meet CPS1 and CPS2 regardless of why the regulation service is no longer available. We believe NERC simply needs the assistance of drafting team to explain the technical reasons why this is already addressed in the existing requirement.</p> <p>Modifying sub-requirement R17.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
US Bureau of Reclamation	<p>The term "AGC" is used through industry and the Reliability Standards. Unless the other standards are modified under this project, it is suggested that it would be more expedient to modify the term AGC to allow for other resources to be included and not worry about the Generation part of the term. This will avoid confusion with other standards, criteria, and procedures. In addition the definition cannot include all resources, just those that are controllable.</p> <p>The Definition should be rewritten as "Automatic Generation Control (AGC): Automatic adjustment of generation and other controllable resources in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus Frequency Bias. ARC may also accommodate automatic inadvertent payback and time error correction." Examples of other Standards that use the term AGC include BAL 003, 004, 005, 006, and BAL-Std-002. In addition the definition cannot include all resources, just those that are controllable. The Definition should be rewritten as "Automatic Generation Control (AGC): Automatic adjustment of generation and other controllable resources in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus Frequency Bias. ARC may also accommodate automatic inadvertent payback and time error correction." Examples of other Standards that use the term AGC include BAL 003, 004, 005, 006, and BAL-Std-002.</p>
Springfield Utility Board	<p>The use of the term "Demand Side Management" is overly broad, may lead to confusion with regard to application of standards, and confusion may reduce reliability. The current proposed language for Regulating Reserve is: Regulating Reserve: Reserve that is responsive to Automatic Resource Control, which is sufficient to provide normal regulating margin. Regulating Reserve may be comprised of generation, controllable load resources, Demand Side Management (DSM), or other resources that have comparable response</p>

Organization	Comment
	<p>characteristics.(Please refer to comments on BAL-002-1)</p> <p>SUB suggest the definition for Regulating Reserve be:Regulating Reserve: Reserve that is responsive to Automatic Resource Control, which is sufficient to provide normal regulating margin. Regulating Reserve may be comprised of generation, controllable load resources, Dispatchable Demand Side Management (DDSM), or other resources that have comparable response characteristics.</p>
<p>NERC Standards Review Subcommittee</p>	<p>#6. Disagree with proposed rewrite of R17. The use of the word “common” within common reference does not improve reliability. There are no common reference devices within the utility industry. This requirement is required to be written for all applicable entities to follow. Since there are many different frequency devices used (from satellite synched GPS receivers to 120 volt plug in models) within the industry, “common” needs to be replaced with “suitable” reference. This will allow applicable entities to calibrate their frequency devices as the manufacture recommends and thus, will improve reliability.</p>
<p>PacifiCorp</p>	<p>1. The word “compromised” under Regulating Reserve definition should be changed to “comprised”.</p> <p>2. Effective Date- Should be lengthened to at least one year to accommodate all of the documentation and system changes/screen updates etc. to modify AGC to ARC.</p> <p>3. R5 -Request clarification of “transmission constraints”.4. R7-modify the following: “manual control to adjust generation resources to maintain the Net Scheduled Interchange”.</p>
<p>Southern Company Transmission</p>	<p>Paragraph 404 - AGC is an industry accepted term that has a specific meaning related to software and telemetry. Controlling load would/does require different software and telemetry. Reference to a new term Automatic Demand Control may be easier. The idea of controlling load for regulation would be a stretch. Doing it for contingencies or capacity makes some sense but regulation does not. One can vary the output of a generator to obtain moment-to-moment regulation but loads would not be expected to have that characteristic due to the real-time uncertainty/variability forced on the customer. A load is normally on or off unlike a generator.</p> <p>Paragraph 415 - Taken from previously posted interpretation in Appendix 1.</p> <p>Paragraph 420 - Seems reasonable to have a backup plan for lost regulation service due to transmission constraints.</p>
<p>Oklahoma Muncpal Power Authority</p>	<p>Paragraph 404: Regulation Reseve should only include Direct Control Load Management.</p>
<p>Consumers Energy Company</p>	<p>Please provide your opinion regarding the Paragraph 404 VSL changes: In Favor Changes for directives in Paragraph 415:</p> <p>Disapprove Comments: In R17, the phrase "or frequency information to the operator" should be deleted as an unnecessary expansion of scope.</p> <p>Please provide your opinion regarding the Paragraph 415 VSL changes: In Favor Changes for directives in Paragraph 420: Approve</p>

Organization	Comment
	Please provide your opinion regarding the Paragraph 420 VSL changes: In Favor
Indiana Municipal Power Agency	Question 5 - Regulating Reserve should not include just any type of DSM. Only the controlled forms of DSM should be included in Regulating Reserves.

8. Do you believe the changes made in response to the directive(s) contained in Paragraph 565 of Order No. 693 are both valid and address the directive(s)?

565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the “for consideration” elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	EOP-001-2	Modified Section B Requirement R4. Modified VSLs for R4.
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Organization	Question 8
Ameren	No
Consumers Energy Company	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Pepco Holdings, Inc. - Affiliates	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
E.ON U.S.	Yes

Organization	Question 8
Entergy Services	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

9. Do you believe the changes made in response to the directive(s) contained in Paragraph 571 of Order No. 693 are both valid and address the directive(s)?

571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	EOP-001-2	Modified EOP-001 instead of EOP-002. Modified Section B Requirement R2.1.
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Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Georgia System Operations Corporation	No
Florida Municipal Power Agency	No
National Grid	No
Xcel Energy	No
Entergy Services	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
E.ON U.S.	No
Oklahoma Municipal Power Authority	No
ERCOT ISO	No

Organization	Yes or No
Indiana Municipal Power Agency	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Kansas City Power & Light	Yes
PacifiCorp	Yes
Santee Cooper	Yes
Springfield Utility Board	Yes
Dominion	Yes
Consumers Energy Company	Yes
Western Electricity Coordinating Council	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Northeast Power Coordinating Council	Yes
IESO	Yes

Comments on the EOP-001 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P571 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will not be responded to individually at this time. However, they will be retained for future consideration.

With regard to the P565 directive, The Response Team has considered the comments received on these modifications and determined that the directive has already been addressed in a previous revision to the standard. Upon Board approval of the remaining balloted and approved standards, this determination will be included in the filing presented to FERC regarding the other standards.

Organization	Question 9 Comment
IRC Standards Review Committee	<p>Paragraph 565 Although the proposed language in R4 addresses the directive, the language is loose and leaves room for interpretation. For example, What constitutes “consider”?; The proposed revised VSLs are too vague as they contain both “consider” ad “appropriate”, both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. The change introduces a need to prove that the functional entity “considered” Attachment 1. Either the change should remain and the industry should expect compliance entities to look for such proof; or the proposal should be dropped and allow the functional entities to include only the “applicable elements”. Further, the comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. We believe that, through this effort, NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards development process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this Standard.</p> <p>Paragraph 571 The proposed change to address paragraph 572 is inappropriate. In the FERC-restructured industry the BA is responsible for balancing supply and demand for the purposes of supporting system frequency, the BA does NOT have any responsibility for transmission other than to follow the constrains and directives imposed by its TOPs. This is an issue of fundamentals and the proposal must be rejected. The FERC directive is better served by simply dropping the BA from the requirement and dropping the constraint “for insufficient generating capacity”. The requirement would then be to have plans for emergencies. The fact is that emergency operating plans are focused on the root causes of the reliability issues and not on the generic cause of the issue.</p>
NERC Standards Review Subcommittee	<p>#9. R2 is applicable to Transmission Operators and Balancing Authorities and R2.1 states that they shall “develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity”. Currently TOPs and BAs have fulfilled this requirement. The proposed addition of “...including emergencies that arise due to a lack of transmission capacity and</p>

Organization	Question 9 Comment
	<p>those whose mitigation plans are hindered by the lack of transmission capability” does not enhance reliability. A Balancing Authority may not be registered as a Transmission Operator or have the ability to see how they impact the entire transmission system that they are a part of. A Balancing Authority may only have the ability to view some of the transmission system that they are a part of and not how they may affect the system overall. This addition is for a Transmission Operator only, the Balancing Authority should be deleted.</p>
Ameren	<p>(a) Section B, R2.1 - unnecessary. Whether the lack of generating capacity was due to a lack of transmission capability or the mitigation is hampered due to lack of transmission capability, it would be dealt with as an emergency due to insufficient generation either way.</p> <p>(b) Section A.5 - As the requirement R5, requires the emergency plan to be updated and reviewed annually, having an effective date that is less than a year away might result in a review between the annual reviews. If the effective date was the first day of the first calendar quarter one year after approval, no extra reviews/update would be necessary.</p> <p>(c) R1 should include the recent interpretation.</p> <p>(d) R2.1 should add "inability of DSM to perform" after insufficient generating capacity</p> <p>(e) R2.1 - lack of transmission is undefined. Is this for n-1, n-2 or for n-7 events?</p> <p>(f) Attachment 1 needs to add a new item #16 - Consideration of DSM performance</p> <p>(g) VSL - Unless there has been numerous instances of non-compliance of EOP-001, the elements which cannot be determined to have been considered for each of the severity level should be one for Lower, four for Moderate, seven for High and more than seven for Very High (not labeled). The proposed numbers are consistent with the current VSL if the rounding is down.</p>
Georgia System Operations Corporation	<p>9) We suggest that R2.1 be re-written as follows: “Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand.”</p>
Florida Municipal Power Agency	<p>For Paragraph 571, the opportunity should be taken to "fix" R2.1, R2.2 and R2.4. R2.1 requires the TOP to Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity, which is the responsibility of the BA, not the TOP. And R2.2 requires the BA to develop, maintain and implement a set of plans to mitigate operating emergencies on the transmission system, which is the responsibility of the TOP, not the BA. And, R2.4 conflicts with EOP-005 in that the TOPs develop the restoration plans, not the BA. This can easily be fixed by including applicability in R2.1 through R2.4, i.e., R2.1 Each BA shall develop ..., R2.2 Each TOP shall develop ..., R2.3 Each TOP and BA shall develop ..., and R4 Each TOP shall develop ...</p>
National Grid	<p>National Grid seeks clarification on “and those whose mitigation plans are hindered by a lack of transmission capability”. The text seems confusing. Suggest deleting the text to enhance clarity.</p>

Organization	Question 9 Comment
Xcel Energy	On 571, Xcel Energy couldn't find any reference to Para 571 in EOP-001.
Entergy Services	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
SERC OC Standards Review Group	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Southern Company Transmission	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
E.ON U.S.	Paragraph 571 states that the ERO needs to "examine whether to clarify" the term insufficient transmission capability. FERC did not mandate insufficient transmission capability be included in the standard requirements.
Oklahoma Municipal Power Authority	Paragraph 571: Specific responsibilities should be better defined. i.e., R.2.1 - BA; R2.2 - TOP; R2.3 - TOP & BA; R2.4 - TOP
ERCOT ISO	<p>Q8 - all the elements of Attachment 1 should be considered during the development of the emergency plan, however, only the chosen emergency plan elements should be assessed for compliance. We believe this is a compound requirement, not a low-hanging fruit, due to necessary industry vetting.</p> <p>Q9 - Modifications to EOP-001-2 R2.1 are unnecessary because R2.2 already addresses emergencies related to transmission capability, including those that may result in the inability to deliver energy from generation capacity.</p>
Indiana Municipal Power Agency	Question 9 - It is not clear what kind of emergencies are being referenced with the new additional language for R2.1. If it is generation emergencies or operating emergencies, then the change should reflect which type of emergencies are to be considered. One could interpret the change to mean all emergencies that are possible which seems to be a huge task.
United Illuminating Company	<p>United Illuminating agrees with the concept but has concerns with the phrase after "and those....". To us the FERC comment of inadequate transmission during the generation emergency is not properly addressed.</p> <p>We suggest changing the edit to:Operating emergencies for:</p> <ul style="list-style-type: none"> 2.1.1 insufficient generation capacity 2.1.2. A lack of transmission capability

Organization	Question 9 Comment
	2.1.3 A lack of transmission capability while executing a plan responding to a generation emergency
Midwest ISO Standards Collaborators	<p>We agree the changes from paragraph 565 are correctly implemented in the requirement. However, the corresponding changes to the VSLs exceed the scope of the directive and, thus, the scope of the SAR. The Commission did not direct changes to the VSLs from percentage of Attachment 1 elements included to the number of missing Attachment 1 elements compliance. While we agree that proposed changes appear to address directives in</p> <p>Paragraph 571, we do not understand how these changes further reliability and do not believe they are needed. When the BA is assessing the adequacy of its resources, it considers its whole portfolio which includes its generating fleet, purchases, sales and ability to receive those sales. There are many reasons collectively that a BA may experience an operating emergency due to insufficient generator capacity. First and foremost, some event will likely have occurred (i.e. extraordinary record heat wave/cold snap, multiple generator failures, inability to import energy, transmission constraints preventing deliverability). Thus, if transmission constraints are preventing the BA from importing energy, the BA will look to its next available resource which may be shedding load. It makes no sense to single out one of the reasons for experiencing an emergency capacity energy shortage. To satisfy the Commission, we suggest that R2.1 could be modified from using “insufficient generating capacity” to “insufficient resource adequacy”. However, this suggestion should be vetted by a drafting team working specifically on EOP-001. Thus, this directive does not represent low hanging fruit. Modifying sub-requirement R2.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
Dominion	Paragraph 571 - While we agree that the change in paragraph 571 meets FERC directives, we do not necessarily agree that the additional language improves the requirement. We suggest that R2.1 be re-written as follows: “Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand.”
Consumers Energy Company	<p>Please provide your opinion regarding the Paragraph 565 VSL changes: Opposed Comments:</p> <p>Relative to R4 and the VSLs presented in the draft standard, some entities (particularly those who have entered into JRO’s regarding BAL-005, but share R4 responsibilities with other entities) may not have available the ability to apply one or more of the elements in Attachment 1. However, if the entity cannot demonstrate to the satisfaction of the Compliance Monitoring Authority that they have indeed considered these elements, and have, for demonstrable cause, determined that these elements are not “appropriate”, it will likely lead to disputes with the Compliance Monitoring Authority when evaluating compliance. “Appropriate” need to be better defined in the context of both R4 and the VSLs.</p>

Organization	Question 9 Comment
	Changes for directives in Paragraph 571: Approve Comments: We recommend changing "insufficient generating capacity" to "insufficient resource capacity"
Western Electricity Coordinating Council	Requirement R4 includes the phrase "and if appropriate." Who or what determines what is or isn't appropriate? This phrase is vague. I suggest you clarify the applicable TOP and BA are the appropriate party to determine which applicable elements in Attachment 1-EOP-001-0 are appropriate to consider when developing an emergency plan.
Pepco Holdings, Inc. - Affiliates	The change did not clarify or enhance the requirement
Northeast Power Coordinating Council	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. Through this effort NERC has addressed FERC's order to "examine whether to clarify this term in the Reliability Standards Development Process" and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this standard.
IESO	We agree that the proposed changes in R2.1 address the directive in Paragraph 571. However, the proposed language in R4, though literally addresses the directive, is loose and leaves room for interpretation as to what constitutes "consider", and the proposed revised VSLs are too vague as they contain both "consider" and "appropriate", both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. More time is needed to develop a meaningful requirement and its associated compliance elements.

10. Do you agree that the directive in Paragraph 577 has already been addressed as noted above?

577	<p>A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.</p>	EOP-002-3 (No changes to standard)	This directive has already been addressed in IRO-006-4.
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Organization	Question 10
Ameren	Yes
American Electric Power	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
E.ON U.S.	Yes
Entergy Services	Yes
ERCOT ISO	Yes
Georgia System Operations Corporation	Yes

Organization	Question 10
IESO	Yes
Kansas City Power & Light	Yes
Midwest ISO Standards Collaborators	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
United Illuminating Company	Yes
Xcel Energy	Yes

11. Do you believe the changes made in response to the directive(s) contained in Paragraph 582 of Order No. 693 are both valid and address the directive(s)?

582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	EOP-002-3	Modified Section B Requirement R2.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.	EOP-002-3	Added Measures for R4, R5, R6, and R7.

Organization	Question 11
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
SERC OC Standards Review Group	No
Southern Company Transmission	No

Organization	Question 11
Xcel Energy	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
United Illuminating Company	Yes

Organization	Question 11
Western Electricity Coordinating Council	Yes

12. Do you believe the changes made in response to the directive(s) contained in Paragraph 573 of Order No. 693 are both valid and address the directive(s)?

573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	EOP-002-3	Modified Section B Requirement R6. Modified VSLs for R6.
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Organization	Yes or No
Xcel Energy	No
NERC Standards Review Subcommittee	No
Ameren	No
Kansas City Power & Light	No
National Grid	No
E.ON U.S.	No
Southern Company Transmission	No
Springfield Utility Board	No
ERCOT ISO	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
American Electric Power	Yes

Organization	Yes or No
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Oklahoma Municipal Power Authority	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
United Illuminating Company	Yes
PacifiCorp	Yes
Georgia System Operations Corporation	Yes
Florida Municipal Power Agency	Yes
Dominion	Yes
Entergy Services	Yes
SERC OC Standards Review Group	Yes
Indiana Municipal Power Agency	Yes
Western Electricity Coordinating Council	Yes
IESO	Yes

Comments on the EOP-002 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P573 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will not be responded to individually at this time. However, they will be retained for future consideration.

With regard to the P577 directive, the majority of commenters agree that this directive has been adequately addressed in Standard IRO-006-4 and hence no further action is required to close out this directive.

Regarding the P582 directive, most commenters agree with the proposed modifications. Some commenters suggest that M5 does not correspond with the wording in R5 and may in fact go beyond the scope of R5. The Response Team agrees with their comment, and has revised M5 as follows:

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)

Organization	Question 12 Comment
IRC Standards Review Committee	<p>Paragraph 582The proposed changes do not address the underlying problem with the entire standard which is how to write emergency standards related to system control. What is an emergency state for a BA? If the BA must balance supply and demand both instantaneously and “on average” then when does an emergency begin for the BA? In Balancing, one could argue the only issue is does the BA have enough supply and if not then shed load. Too much supply is handled by exercising its authority over GOPs. Such fundamental issues must be discussed before expediting minor adjustments.</p> <p>The change to R2 does nothing to clarify what it means to “reduce risk” or what “as required” means (does this mean if something bad happened that the entity by definition is non-compliant since it obviously didn’t do “what was required to address the problem”?). How is risk measured?</p> <p>Measure 2 requires the entity to show that its acts were in “conformance” with its plans. Does that preclude a system operator from varying with a particular step in its own emergency plans?Does approval of the proposed changes constitute an approval of EOP-002? This is important because:R4, R5, R6 are examples of requirements that need a major rewriting, or at least major discussion.</p> <p>R4 imposes an immeasurable “anticipation” step. Without being able to measure “anticipation” this requirement has no meaning. An entity that did not “anticipate” the emergency cannot be held non-compliant with R4!</p> <p>R5 treats frequency control as if it were a fine-tuning process. Moreover, as written R5 places a ceiling on how much real power may be exchanged over and above its scheduled interchange. Since ACE already introduces a bias for the frequency, it would seem that “any” non-</p>

Organization	Question 12 Comment
	<p>zero ACE would represent non-compliance to this requirement. The standard was written with regard to correcting frequency - but in the mandatory compliance world the “intentions” of the entity is not measureable so any error could be assumed to be used to assist frequency.</p> <p>R6 is unclear. What constitutes “immediately”? If all remedies are optional, then no remedy is required, making compliance a moot point.</p> <p>The proposed M5 does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as</p> <p style="padding-left: 40px;">“...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes.”</p> <p>Paragraph 573The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.</p> <p>Response: Specific to the comment on Paragraph 582, this project was initiated to develop standard changes as indicated in the listed directives. Making changes to other parts of the standard that are not affected by the directives is beyond the scope of this Project. Implementing and approving the proposed changes do not imply that the standard will not be revised in the future to improve the overall quality and clarity of the standard.</p> <p>With respect to M5, the Response Team agrees with your comment, and has revised M5 as follows:</p> <p style="padding-left: 40px;">M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)</p> <p>Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
<p>NERC Standards Review Subcommittee</p>	<p>#12. R6.3 and R6.8 should be replaced by using Direct Control Load Management (DLCM). As described in the NERC Glossary of terms: DLCM is “Demand-Side Management (DSM) that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand”. Per NERC Glossary of terms, Demand Side Management is undertaken by the Load Serving Entity or its customers, whereas DCLM is under the direct control of system operators. NERC’s Glossary of terms goes on to define a system operator as “an individual at a control center (BA, TOP, GOP, RC) whose responsibility it is to monitor and control that electric system in real time”. DCLM should be used in place of DSM since it has more</p>

Organization	Question 12 Comment
	<p>applicable entities per NERC definition.</p> <p>Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
Ameren	<p>(a) R 6.8 - Unknown technologies are not "technically feasible". Delete this sub requirement.</p> <p>(b) In Attachment 1, Alert 1 - does "All Available Resources" include DSM? If resources are comparable, why wouldn't it be?</p> <p>Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
Kansas City Power & Light	<p>Directive 573:Sub-requirement R6.8 is ambiguous and subject to interpretation and recommend removal. The other sub-requirements R6.1 through R6.7 are sufficiently comprehensive as available recovery actions and the removal of R6.8 does not compromise the response to the directive language to be addressed. In addition, although not one of the changes submitted, requirement R6 should be considered modified to reflect language that targets maintaining a balance of energy resources and energy obligations in real time. The current references to Control Performance and Disturbance Control Standards over longer operating ranges does not accurately reflect the need for immediate operator actions. Recommend modifying the language to "cannot maintain ACE within Lsub10 limits, then . . .".</p> <p>Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.</p>
National Grid	<p>In Order 693, the Commission correctly determined that "With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered "low hanging fruit" and should be will be fully vetted in the next iteration of this standard. Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.</p> <p>Response: The Response Team thanks the commenter for the thoughtful comments. These comments touch on areas that are beyond the scope of this project. We will forward your comments to the NERC Standards Committee for its consideration.</p>

Organization	Question 12 Comment
	<p>Specific to the comment on Paragraph 582, the proposed changes to R2 and the addition of M5 and other compliance elements were directed by the Commission and the ERO must comply. In response to other commenter’s suggestion, the Response Team has revised M5 as follows:</p> <p style="padding-left: 40px;">M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)</p>
<p>E.ON U.S.</p>	<p>In paragraph 582, FERC says to “consider” Measures. E ON U.S. believes the added Measures are not mandated by FERC. E ON U.S. also believes these added Measures neither improves reliability nor changes the obligation of the BA to provide evidence upon request.</p> <p>In response to paragraph 573, E ON U.S suggests using the term “technically feasible resource options,” not “any available alternative technologies.” “Any available alternative technologies” is too broad & omits the technical requirements qualification required by FERC. E ON U.S. suggests the following edits:</p> <p style="padding-left: 40px;">R6.8. Deploying any technically feasible resource options not included above that are designed to supply energy to or reduce demand on the Bulk Electric System.</p> <p>Response: Specific to the comment on Paragraph 582, the proposed changes to R2 and the addition of M5 and other compliance elements were directed by the Commission and the ERO must comply.</p> <p>Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
<p>Southern Company Transmission</p>	<p>Paragraph 577 - Addressed in IRO-006. Does something need to be filed with NERC or FERC to explain that?</p> <p>Paragraph 582 - R2- Not sure words clarify anything. What if two actions are required under the plan for a situation but they only took one. Should it not be something like “ ... shall take actions required and appropriate for an emergency situation as described in its capacity and emergency plan or substitute alternative actions as appropriate to the current situation based on operator discretion to reduce risks to...”If this is changed, then M2 needs to change to reflect any changes.</p> <p>Paragraph 573 - Not sure why R6.3 is needed. Demand Side Management could be put in the list for R6.7 and be less controversial. As stated earlier, although FERC states that “demand response covers considerably more resources than interruptible load” it is not clear to any reader what that might be. Expect confusion to cause problems with proposed changes being low hanging fruit.Note: Demand-side management is explicitly listed in Alert 2 in current Attachment 1</p> <p>Response: Specific to Paragraph 577, NERC will file with FERC to explain that this directive has been addressed in IRO-006-4.</p> <p>Specific to Paragraph 582, the Response Team does not think the proposed alternate wording adds any clarity to the wording proposed in the draft standard, which already provides the flexibility needed to address the energy/capacity emergency situation while adhering to the entity’s</p>

Organization	Question 12 Comment
	<p>emergency plan.</p> <p>Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
Springfield Utility Board	<p>Please refer to BAL-002 and BAL-005 comments R6.3 is proposed to state "R6.3. Deploying all available Demand-Side Management options," "Demand-Side" is not a term in the NERC definitions. The dash should be removed.</p> <p>Demand Side Management should be changed to Dispatchable Demand Side Management. This should be changed to R6.3 is proposed to state "R6.3. Deploying all available Dispatchable Demand Side Management (DDSM) options,"</p> <p>Response: The Response Team has considered the comments received and determined that modifications to R6 to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
ERCOT ISO	<p>Q11 - Proposed revisions to R2 appear to address the directive, however the language comes short of criteria for a good requirement. It is not clear when the action is required or when it is appropriate. This may prove to be controversial.</p> <p>Q12 - This would require significant developmental work to describe how to determine technically equivalent performance. The Requirement 6.3 change includes the use of the defined term DSM, which needs to be in sync with the effort of the Demand Response Data Availability System (DADS) team.</p> <p>Response: Specific to R2, the project was initiated to address the outstanding directives, and the Response Team believes the language is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions.</p> <p>Specific to R6 and its sub-requirements, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
Midwest ISO Standards Collaborators	<p>The changes to R2 are unnecessary and only state the obvious. A capacity and emergency plan must identify when it is appropriate and required to take actions. Adding the clause to R2 provides no reliability benefit. Furthermore, the directive only requires the ERO to address ISO-NE concern, not to necessarily modify the standard. The concern should be addressed by a simple explanation that if their plan allows them to skip steps, they have met the requirement by having a plan and implementation of their plan allows them to implement only what is necessary.</p> <p>We disagree with adding Measures through this standards action. FERC was clear in paragraph 616 from Order 693 that determination of the need for a requirement to have a measure was at the ERO's discretion. Thus, measures do not appear to be a major concern of FERC and making changes to measures will not demonstrate a commitment to complete directives from Order 693. Thus, there is no need to make</p>

Organization	Question 12 Comment
	<p>changes to measures through an expedited process.</p> <p>Measurement 5 is fundamentally incorrect. R5 is intended to limit a BA's assistance on the Interconnection to the frequency response obligation established by the frequency bias settings for a few minutes (up to 15) after the loss of a resource. Measurement 5 reads to limit all Interconnection assistance and could be construed as limiting the import schedules. The wording should be made parallel to the requirement. We suggest:</p> <p style="padding-left: 40px;">“The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes.</p> <p>(Requirement 5)“We do not believe the directive in paragraph 573 represents low hanging fruit. We are supportive of using DSM but we believe a drafting team needs to carefully work through addressing this directive to avoid unintended consequences. Based on the proposed definition of DSM in BAL-002, it is not clear if interruptible load is distinctly differently or one of the various types of DSM. If it is one of the various types of DSM, then R6.4 is duplicative of R6.3. Further changes may be required to the standard to address the directive as well. For example, why would R4 not include notifying the “end-use customers, Load-Serving Entities, or their agents or representatives” to anticipate the need to call upon DSM? Adding sub-requirements</p> <p>R6.3 and R6.8 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p> <p>Response: Specific to R2, the project was initiated to address the outstanding directives, and the Response Team believes the language is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions.</p> <p>Specific to the comment on M5, the Response Team has revised M5 as follows:</p> <p style="padding-left: 40px;">M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)</p> <p>Specific to R6 and its subrequirements, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>

Organization	Question 12 Comment
<p>Northeast Power Coordinating Council</p>	<p>This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.</p> <p>In Order 693, the Commission correctly determined that “With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO’s Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered “low hanging fruit” and should be will be fully vetted in the next iteration of this standard.</p> <p>Response: Specific to R2, the proposed changes are intended to comply with directives as stipulated. We are not certain that the ISO-NEs view now expressed fully takes care of the FERC’s directive in Paragraph 582.</p> <p>Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
<p>PacifiCorp</p>	<p>1. R6.8 Internal comment---This requirement illustrates the need for additional DSM resources.</p> <p>2. M5-Request clarification.</p> <p>Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.</p>
<p>Georgia System Operations Corporation</p>	<p>10) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last.</p> <p>11) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last.</p> <p>12) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last.</p> <p>Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6</p>

Organization	Question 12 Comment
	<p>and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.</p>
<p>Florida Municipal Power Agency</p>	<p>For Paragraph 577, we "ABSTAIN", as we do not understand why this is being balloted since there is no change. Response: We conducted the ballot to seek the industry's concurrence that the directive has been taken care of.</p>
<p>Dominion</p>	<p>Paragraph 582 - While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.</p>
<p>Entergy Services</p>	<p>Paragraph 582 - While we do not believe that the sub-requirements of R6 are intended to be executed in order, we suggest that R6.8 should be ordered prior to reducing load. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.</p>
<p>SERC OC Standards Review Group</p>	<p>Paragraph 582 - While we do not believe that the sub-requirements are intended to be executed in order, we suggest that the sub-requirement that includes reducing load should always be last. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.</p>
<p>Indiana Municipal Power Agency</p>	<p>Question 10 - Abstain. If this issue has been addressed, why is it being covered in this area of commenting? Response: We conducted the ballot to seek the industry's concurrence that the directive has been taken care of.</p>
<p>Western Electricity Coordinating Council</p>	<p>Requirement R2 includes the phrase "and as appropriate." Who or what determines what is or isn't appropriate? We agree with the concept that not all actions included in the plan need to be implemented for every event, but this phrase is vague. Suggest clarifying tha that the BA is</p>

Organization	Question 12 Comment
	<p>the appropriate party to determine which actions are appropriate.</p> <p>Response: The proposed changes are intended to comply with directives as stipulated, and it is the Response Team’s belief that the language proposed is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions.</p>
IESO	<p>Specific to the changes to the Measures, etc. to comply with the directive in paragraph 582, we do not agree with the proposed M5 since the second part does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as “...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes.”</p> <p>Response: Other commenters have also expressed a similar concern. The Response Team has revised M5 as follows:</p> <p>M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)</p>

13. Do you believe the changes made in response to the directive(s) contained in Paragraph 601 of Order No. 693 are both valid and address the directive(s)?

601	<p>We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process.</p> <p>598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.</p>	EOP-003-2	Modified Section B Requirement R3.
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Organization	Question 13
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No

Organization	Question 13
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
PacifiCorp	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
United Illuminating Company	No
Xcel Energy	No
CECD	Yes
National Grid	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Western Electricity Coordinating Council	Yes

14. Do you believe the changes made in response to the directive(s) contained in Paragraph 603 of Order No. 693 are both valid and address the directive(s)?

603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	EOP-003-2	Added Section B Requirements R9 and R10. Added VSLs for R9 and R10.
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Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Northeast Power Coordinating Council	No
Georgia System Operations Corporation	No
National Grid	No
Western Electricity Coordinating Council	No
Arizona Public Service Company	No
Consumers Energy Company	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
E.ON U.S.	No
Dominion	No
Entergy Services	No

Organization	Yes or No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Santee Cooper	No
American Electric Power	No
Central Lincoln	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
CECD	No
United Illuminating Company	No
Oklahoma Municipal Power Authority	No
PacifiCorp	No
IESO	No
Midwest ISO Standards Collaborators	No
Pepco Holdings, Inc. - Affiliates	Yes
Xcel Energy	Yes

Comments on the EOP-003 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P601 and P603 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 14 Comment
IRC Standards Review Committee	<p>Paragraph 601 Taken in isolation the concept of adding a list of entities with whom the TOP and BA must coordinate is reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the requirement as written. Regarding R3, the concept of “coordination” is vague and undefined. There are several issues that make this seemingly trivial request more complex than the requestor makes it out to be.</p> <ul style="list-style-type: none"> o The standard itself is included in Project 2007-01 o The concept of “coordination” is vague and undefined o There is no measurement nor VSL for R3 o Who is non-compliant if one or more of the list entities does not participate? o Aren’t all TOPs and BAs in an interconnection “interconnected”? <p>Paragraph 603 The directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of “simulation” (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a “drill” which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation.</p> <p>Requirement R8 as written goes outside of the scope of the directive.</p> <p>Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be developed through the normal process not through this much abbreviated process. It follows that we do not agree with the VSLs for this Requirement. There is a coordination concern with Project 2007-01 that is currently underway. Project 2007-01 whose latest draft is being posted for balloting and comment proposes to revise EOP-003 by removing UFLS reference from the latter standard. If the PRC-006/EOP-003 pair is approved, it will render the version being used for making changes to address the</p>

Organization	Question 14 Comment
	<p>low-hanging fruit directive invalid. Further, there should not be two versions of the same standard to be posted for balloting at the same time.</p> <p>We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.</p>
<p>NERC Standards Review Subcommittee</p>	<p>#13. R3 requires a TOP and BA to coordinate load shedding plans with each interconnected TOP and BA along with Regional Entities within whose regions they operate and RC(s) associated with overseeing the operations of the BA or TOP, plus GOs within the appropriate BA area or TOP area. This multiple coordination effort harms reliability of the BES and will only add confusion and frustration. Many TOPs and BAs are registered within multiple regions and this proposed continent wide reliability standard does not take into consideration how present day entities support the BES, daily. The following is a proposed rewrite to R3 and its sub requirements:</p> <p>R3. Each Transmission Operator and Balancing Authority shall coordinate manual load shedding plans with at least one of the following:</p> <ul style="list-style-type: none"> R3.1 Physically connected Transmission Operators and Balancing Authorities or R3.2 Regional Entities within whose regions they operate or R3.3 Reliability Coordinator(s) associated with overseeing the operations of the Balancing Authority Area or Transmission Operator Area and R3.4 Generator Owners within the Balancing Authority Area or Transmission Operator Area, as appropriate. The above rewrite now gives clarity with whom the TOP and BA is required to coordinate their manual load shedding plans with. Manual is inserted since UFLS and UVLS are noted within other standards and all load shedding (outside of UFLS and UVLS) is done manually. Presently many entities follow the Regional Entity’s plan and this fulfills all sub requirements of R3. <p>#14. R8 (Note this requirement does not match up with NERCs Comment column above) Request that in order to prove clarity, R8 be rewritten as FERC stated within Order 693 to require periodic drills of simulated load shedding. R8 to read</p> <p>“At least annually, each Transmission Operator and Balancing Authority shall simulate load shedding as stated within their respected load shedding plan”.</p> <p>This rewrite will enable the TOP or BA to simulate load shedding as they plan, not practice load shedding by the use of simulation.</p> <p>#14. R9 (Note this requirement does not match up with NERCs Comment column above) R9 should be deleted in its entirety since paragraph 603 states “ 603. The Commission approves proposed Reliability Standard EOP-003-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and Â§ 39.5(f) of our regulations, the Commission directs the ERO to develop</p>

Organization	Question 14 Comment
	<p>a modification to EOP-003-1 through the Reliability Standards development process that:</p> <p>(1) includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and</p> <p>(2) requires periodic drills of simulated load shedding”. R9 does not address the Commissions interests.</p>
Ameren	<p>(a) R3.4- This standard does not apply to Generator Owner, but the requirement is to coordinate with them. What reason would GO have to comply if there are no consequences of non-compliance. It will be difficult to coordinate with a GO having no measure for compliance</p> <p>(b) On the other hand, R3 does not require to coordinate with LSE and DP, but R9 does. Again the standard does not apply to LSE or DP and for that reason would be difficult to coordinate for R9. (c) R8 - what does "test through simulation " mean? Does that mean table top drills, actual signals but not implemented, load flow and dynamic model simulations? This requirement is vague.</p>
Northeast Power Coordinating Council	<ol style="list-style-type: none"> 1. These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. 2. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9. 3. What are personnel deployment drills? Are these applicable to automatic load shedding? 4. Requirement R9 is not in the directive; and is outside the scope of the directive.
Georgia System Operations Corporation	<p>13) IF TOPs and Bas are required to coordinate with RCs, REs, and GOs, they should be included as applicable entities and have a requirement to participate in the coordination of plans with their TOPs and BAs?</p> <p>14a) Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.</p> <p>14b) Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. Tabletop exercises should be acceptable. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard.</p> <p>14c) It isn't clear what Measure M2 refers to now. The VSL requirement changes appear to be mis-numbered.</p>

Organization	Question 14 Comment
National Grid	<ul style="list-style-type: none"> o National Grid seeks clarification and possible examples for the term “simulation”. o There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9 where LSE and DP have been added but are not included in the Applicability section. o What are personnel deployment drills? Are these applicable to automatic load shedding? o Requirement R9 is not in the directive; and is outside the scope of the directive.
Western Electricity Coordinating Council	<p>Agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. Once every two years is too often for tests. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. Suggest a similar time requirement here. Also believe that new Measures should be developed for any added Requirements.</p>
Arizona Public Service Company	<p>AZPS believes that R2 and R3 should be removed from this standard. In addition, AZPS agrees with the comments of FMPA as follows: there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not complement each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated. EOP-003, as proposed, is disturbing in the sense that it requires simulation of the effectiveness of load shedding plan (R7- new) and test of load shedding plan (R8- new), without specifying the scope and clarifying what it means.</p>
Consumers Energy Company	<p>Changes for directives in Paragraph 601: Disapprove Comments: Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy.</p> <p>Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.</p>

Organization	Question 14 Comment
	<p>Please provide your opinion regarding the Paragraph 420 VRFs and VSLs: Opposed Comments: Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy.</p> <p>Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.</p>
<p>Kansas City Power & Light</p>	<p>Directive 601:It is inappropriate to include Regional Entities as an entity to coordinate load shedding. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to coordinate operating actions or schemes as defined in this Standard EOP-003. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.</p> <p>Directive 603:It is unclear as to the extent a "simulation" is intended in requirement R8. Recommend clarifying the simulation as a form of modeling and not intended as exercise of actual actions. In addition, what is to be simulated here? There are two forms of load shedding action. Automatic load shedding based on frequency and/or voltage and manual load shedding by operator action. What is the intention?</p> <p>It is unclear what "test" in requirement R9 represents. Recommend clearly indicating the intent is a test of the plans under table-top drills or other modeling techniques.</p>
<p>Florida Municipal Power Agency</p>	<p>For Paragraph 601, this is probably a case of miscommunication between Drafting Teams under tight time pressure, but, there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not compliment each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated.</p>

Organization	Question 14 Comment
	<p>For Paragraph 603, the Commissions language is much clearer than the proposed R8 and R9. The commission directed "periodic drills of simulated load shedding", which means they want us to perform drills. R8 and R9 changes the object to "test" which introduces ambiguity that is wide-open to numerous interpretations. R8 and R9 should be revised to clearly show that "drills" are required as directed by the Commission. "Drills" are much less open to interpretation than "tests". In addition, the Commission was clear that the "drill" they are directing ought to include as part of the exercise "simulated load shedding", which is clear that the Commission does not expect engineering simulations, but rather a drill that simulated the decision making environment operators would be exposed to. R8 as proposed introduces the same ambiguity that is currently within EOP-005-1 R7 by saying "test their load shedding plans through simulation". This introduces the ambiguity that has spurred requests for interpretation in EOP-005-1 R7: is simulation a "drill" or an engineering computer simulation? While FMPA believes that EOP-005-1 R7 also means a "drill", compliance has believed otherwise. Here it is clearly a drill that is required. We ought to stay away from words that add ambiguity such as "simulation" and "test" and stick with words that are more clear, like "drill". (Note that the ballot refers to R9 and R10 whereas the proposed draft adds R8 and R9 and there is no R10, we assume this is a typo in the ballot)FMPA opposes the opinion regarding</p> <p>Paragraph 603 VSL Changes. Note that the question title says Paragraph 420, which we assume to be a typo and should refer to Paragraph 603. See comments to "Changes for Directives in Paragraph 603" (above).</p>
E.ON U.S.	<p>In paragraph 601 FERC says to “consider the comments...in future modification”, not to actually change requirements. The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive.</p> <p>The revision to R3.4 adds Generator Owners when the need for load shedding coordination needed between a TOP/BA and GOs arises when load is shed automatically based on frequency or voltage levels. This should be covered under other standards. It is not clear to E ON U.S. why the TOP/BA need to coordinate a manual load shed program with the GO.</p> <p>There are errors in the numbering for VSLs R8, R9, and R10.</p> <p>There is no R10 in the Requirements Section.</p>
Dominion	<p>Paragraph 601 - Although we agree that the changes meet the FERC Directive, we suggest the this version is premature given that Project 2007-01 (Underfrequency Load Shedding) contains requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01.</p> <p>Paragraph 603 -R8 The term “simulation” needs to be better defined to allow entities to comply with the intent without increasing the potential for shedding load to be inadvertently implemented. R9 expands the applicability to load serving entities and distribution providers, which are not listed in the Applicability section of this draft standard. We suggest the SDT either add these entities to the Applicability section or remove these entities from R9.</p>

Organization	Question 14 Comment
Entergy Services	<p>Paragraph 601 - Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.</p> <p>Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard and should not be included.</p> <p>Paragraph 603 concerns the simulation of and periodic drills for load shedding plans. The added requirements R8 and R9 addressing Paragraph 603 contain the “Time Horizon: Long-Term Planning, Operations Planning”. We believe these requirements do not apply to Long-Term Planning Time Horizon and that term should be deleted.</p>
SERC OC Standards Review Group	<p>Paragraph 601 - Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.</p> <p>Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard.</p>
Southern Company Transmission	<p>Paragraph 601 - Requirement R3 does not clarify the current ambiguity about what type of load shedding - automatic or manual. R1 is clearly Automatic and APPA and ISO-NE talk in Order 693 about “trip settings” which imply automatic as well. Furthermore, the UFLS drafting team has already proposed changes to EOP-003 that are not coordinated with these changes to remove UFLS completely from this standard into of PRC-006. That set of changes to those standards will be balloted simultaneously with these changes based on the dates on NERC’s website.</p> <p>Paragraph 603 - NERC Comments note revisions for R9 & R10, but R10 does not exist on published copy of draft. R8 & R9 appear to be the ones added. Also has incorrect references to R9 & R10 in VSL. And again, what type of load shedding? In R8, the term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load.</p>
Santee Cooper	<p>Paragraph 601 - the meaning of “coordinate” needs to be clarified. In addition, EOP-003-1 is in the pre-ballot review period for the</p>

Organization	Question 14 Comment
	<p>third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard. Paragraph 603 - FERC directed these changes go through Reliability Standards process. We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process. In addition, EOP-003-1 is in the pre-ballot review period for the third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard.</p>
<p>American Electric Power</p>	<p>Paragraph 601With respect to R3.4., AEP recommends that it would be more applicable for the coordination to occur between Transmission Operator (TOP) or BA and Generator Operators rather than Generation Owners. In many cases, these are separate entities and it is our experiences that the GO is not always the appropriate entity regarding the sharing of these plans.AEP does not see the benefit in sharing the load shedding plans with the RE. Based on the division of responsibilities, some RE's mainly only have compliance staff and do not have expertise with addressing the plan. If a particular RE wanted to see the plan, AEP would work with that entity. Creating a process to send data to entities that do not need the information, simply for the sake of demonstrating compliance, does not advance the goal of increasing reliability.Paragraph 603Drills should be and are already covered under the training standards. There is no need to have redundant requirements that create overlaps.</p> <p>Furthermore, the addition of R9 does not seem to be justified as part of the FERC directive in Paragraph 603.</p>
<p>Central Lincoln</p>	<p>Project 2007-01 is also rewriting this standard, and the two versions conflict.</p>
<p>ERCOT ISO</p>	<p>Q13 - Coordination with the Regional Entities may not be universally applicable due to variations in the way Regional Entities are organized. Regional Entities need to know about the load shedding plans, but the planning and development may not need to include Regional Entities unless they perform such function.The RC should be made aware of load shedding plans and capabilities, but actual coordination should likely be with the PC. The NERC Project 2007-01 UFLS proposes that the PC determines load shedding programs.-</p> <p>Q14 - The directives ask for including requirement for periodic drills of simulated load shedding. The wording in the proposed R8 asks for testing the load shedding plan through simulation. The directive simply requires a "drill" which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation.</p> <p>Requirement R8 as written goes outside of the scope of the directive.R9 is not asked for by the directive.</p>
<p>Indiana Municipal Power Agency</p>	<p>Question 13 - Under the UFLS Project, the UFLS SDT has removed UFLS from this standard draft posted for commenting and voting in project 2007-01. The side by side commenting and balloting of the same standard seems to add confusion to the process.</p> <p>Question 14 - The Commission is looking to have perodic drills of simulated load shedding performed and not just tests. The interpretation of "test" is open to each entity and just running an engineering computer simulation does not meet the directive.</p>

Organization	Question 14 Comment
CECD	Question 14. The directive specifically states that there should be periodic drills of simulated load shedding” and CECD recommends R9 be modified to include testing through simulation of the applicable load shedding plan.”
United Illuminating Company	<p>R3 should specify it is manual load shedding or operator initiated loadhedding, so as not to be confused with ufls, uvls, or sps.</p> <p>R8 will require an interpretation of the word “simulation”. Is a simulation having a single operator on a SCADA development system initiate a simulation, or a table top, or a planning study showing that load can be dropped?R9 will require clarification on whether this is a single test coordinated with all entities participating at the same time on an area basis.</p> <p>R9 item 2 states personnel deployment shall be included, but not every entity requires to dispatch personnel to deploy manual load shed. The phrase “ as required by the manual load shed plan” should be added.</p>
Oklahoma Municipal Power Authority	There are two versions of EOP-003 currently posted for ballot and they are in conflict with one another. Recommend moving UFLS and UVLS to the PRC standards and only addressing manual load shedding in this standard.Define "tests". Would prefer the language directly from the Commission which stated "periodic drills of simulated load shedding". We find this language less ambiguous.
PacifiCorp	<p>This needs to be coordinating with PRC-006-01 which is also out for comments. The requirements under R2 is already part of requirements under PRC-007 (new PRC-006-01) and PRC-010. The requirements under R4, R7 and R8 are part of requirements under PRC-007 (new PRC-006-01) .</p> <p>EOP-003 load shedding should be limited to manual load dropping, automatic load shedding occurs based on system conditions without operator interventions.Suggest voting NO on EOP-003.</p>
IESO	<p>We agree that changes to Requirement R3 address the directive in Paragraph 601, but disagree with the proposed addition of R8 and R9 to address Paragraph 603. Also, we have a coordination concern which we will raise after address the concerns with changes to meet the directive in Para. 603.</p> <p>Paragraph 603 of the directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of “simulation” (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a “drill” which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation.</p> <p>Requirement R8 as written goes outside of the scope of the directive. On the other hand, R8 should include testing the readiness and functionality of procedures for system operators as well as distribution personnel and LSEs as per Paragraphs 596 and 597 respectively.Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to</p>

Organization	Question 14 Comment
	<p>develop, and hence should be developed through the normal process not through this much abbreviated process. In addition, the meaning of the term “personnel deployment drills” in a requirement that asks for testing of the load shedding plan. It is more appropriate to clearly stipulate the intent or expected outcome of the drill rather than stipulating a term that is subject to different interpretation. It follows that we do not agree with the VSLs for this Requirement.</p> <p>Furthermore, Section 4 of this standard should also include Load Serving Entity and Distribution Provider to be consistent with this requirement. We also have a coordination concern with Project 2007-01 that is currently underway. We have a coordination concern with Project 2010-12 that is currently underway. Project 2010-12 on EOP-003-2 standard, whose latest draft has been posted for balloting and comment, revised EOP-003-2 with the intent to address two directives (601 & 603) in FERC Order 693. If the EOP-003-2 is approved, it will render the version being used for making changes to address the UFLS reference redundancy invalid in EOP-003-1 standard. If the ballot on EOP-003-2 fails, the work to address the directives of FERC Order 693 should be assigned to the Project 2007-01 SDT for inclusion in the next draft. Further, there should not be two versions of the same standard posted for balloting at the same time.</p> <p>We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.</p>
Midwest ISO Standards Collaborators	<p>We disagree with the changes to address the directives in paragraph 601. No where does the directive require changes to be made. It only requires consideration of changes. How was this consideration made? Our understanding is that no drafting team was ever convened to discuss these changes. Thus, on this merit alone, the changes should be removed to be considered by a drafting team. Furthermore, the UFLS drafting team has already proposed changes to EOP-003 that are not coordinated with these changes to remove UFLS completely from this standard into of PRC-006. That set of changes to those standards will be balloted simultaneously with these changes based on the dates on NERC’s website. Coordinating load shedding plans with regional entities does not make any sense in today’s environment and is a vestige of the pre-enforcement area. The regional entities have no operating responsibilities and all the legal authority they need to review/request a registered entity’s load shedding plan. We are not convinced that the load shedding should be coordinated with the RC. Clearly, the RC should be made aware of load shedding plans and capabilities. Any coordination, however, would be of the automatic load shedding plans and should probably occur through the PC. That is precisely what the UFLS project is proposing that will be balloted simultaneously with this set of changes.</p> <p>Adding sub-requirements R3.1 through R3.4 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>

Organization	Question 14 Comment
	<p>We believe R8 and R9 miss the entire point of the directive. The directive appears to be focused on exercising the load shedding plans without actually shedding load. Specifically, the Commission states “periodic drills of simulated load shedding”. We believe the Commission did not include “simulated” for the purpose of simulating load shedding in a power flow or dynamics study for instance. If they had intended this, the requirement would have applied to the PC or TP. Rather, we believe the Commission used the word “simulated” before load shed to make it clear they did not intend for actual load to be shed during the drills. Further support for this position can be gathered by reviewing the Commission’s directives and understanding of the UFLS standards in Order 693.</p> <p>Furthermore, we believe R8 and R9 should be written and addressed by a standards drafting team. These are significant issues and testing of load shedding plans is no small task. Because it will require the coordination of multiple registered entities, only a standards drafting team with the appropriate participation would be in a position to assess the appropriate requirement here and how often the tests should occur. Otherwise, we could end up with a reduction in reliability with actual load being shed from failure to properly coordinate tests or to understand that they are tests being conducted to comply with NERC standards.</p>

15. Do you believe the changes made in response to the directive(s) contained in Paragraph 612 of Order No. 693 are both valid and address the directive(s)?

612	<p>APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.</p>	EOP-004-2	<p>Modified Section B Requirement R2 and added Requirement R3. Added VSL for R3.</p>
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Organization	Question 15
Ameren	No
American Electric Power	No
CECD	No
Central Lincoln	No
Consumers Energy Company	No
Dynergy Inc.	No
E.ON U.S.	No
ERCOT ISO	No
Georgia System Operations Corporation	No
Illinois Municipal Electric Agency	No
Indiana Municipal Power Agency	No

Organization	Question 15
Kansas City Power & Light	No
National Grid	No
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Santee Cooper	No
Southern Company Transmission	No
Xcel Energy	No
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Midwest ISO Standards Collaborators	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes

Organization	Question 15
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

16. Do you believe the changes made in response to the directive(s) contained in Paragraph 615 of Order No. 693 are both valid and address the directive(s)?

615	<p>The Commission declines to address Xcel’s concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process.</p> <p>608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.</p>	EOP-004-2	<p>Addressed definition of “Reportable Event” by adding reference to Attachment 1 in Section B Requirement R4.</p> <p>NERC concurs with FERC that Xcel’s concerns regarding the WECC process should be handled through a request for a Variance.</p> <p>With regard to distribution of reports, NERC currently addresses this as the ERO.</p>
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Organization	Yes or No
Xcel Energy	No
Dynergy Inc.	No
Ameren	No
Northeast Power Coordinating Council	No
E.ON U.S.	No
Florida Municipal Power Agency	No
National Grid	No
Southern Company Transmission	No

Organization	Yes or No
American Electric Power	No
Oklahoma Municipal Power Authority	No
CECD	No
US Bureau of Reclamation	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
IESO	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
Springfield Utility Board	Yes
NERC Standards Review Subcommittee	Yes
Georgia System Operations Corporation	Yes
Consumers Energy Company	Yes

Organization	Yes or No
Kansas City Power & Light	Yes
Illinois Municipal Electric Agency	Yes
Santee Cooper	Yes
Western Electricity Coordinating Council	Yes

Comments on the EOP-004 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P612 and P615 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 16 Comment
IRC Standards Review Committee	<p>Paragraph 612 Taken in isolation the proposed change to R2 is appropriate. In the context of the entire requirement, the proposed changes to R2 and R3 are vague as written. The requirements mandate “prompt analysis”. FERC has requested NERC to avoid that kind of ambiguous phrase. The sub requirement R3.1 emasculates the main requirement by introducing “at a minimum”. From the FERC directive, it seems that only the sub requirement is needed and the main requirement should be deleted.</p> <p>Paragraph 615 The proposed change to the definition of “Reportable Event” is in direct competition with the Event Analysis Working Group’s initiative to define Event Categories. That initiative is posted for comments.</p>
ERCOT ISO	<p>Q15 - The R3 proposed language is not required by the directive. The directive also does not require adding the Distribution Provider. The R2 language that exists covers the directive. The proposed sub-requirement is unnecessary because it is implied in the existing R2 language.</p>
Indiana Municipal Power Agency	<p>Question 15 - It is not clear if the entities in requirement 3 have to analyze just the BES disturbances within their own system or facilities, or if these entities have to include analysis of BES disturbances outside of their system and the affect of essentially all BES disturbances on their system or facilities. It is also not clear how these entities in requirement 3 will be made aware of such BES disturbances, especially BES disturbances outside of their system or facilities (if applicable).</p> <p>Question 16 - Abstain. IMPA is not sure if the Xcel concern has been addressed and cleared up entirely.</p>
Central Lincoln	<p>The requirement to provide the information to the Reliability Coordinator is not valid in the West, where the WECC RC has stated they do not want to deal with every registered entity. http://www.bpa.gov/corporate/business/reliability/Docs/2007/PNSC_RE_Data_Letter_2_070723.pdf. This policy has not changed with WECC as the RC.</p>
Dynergy Inc.	<p>#15 - Since Requirement R3 was modified and Requirement R3.1 was created to capture the responsibility of the GOP and LSE, Requirement R4 should also be modified by deleting the GOP and LSE from this Requirement R4 since the responsibility is now covered</p>

Organization	Question 16 Comment
	<p>in in Requirement R.1 Also, R3.1 should be revised so the responsible entity only includes information to the RC, BA, or TOP upon request.</p> <p>#16 - Attachment 1 was already part of the Standard thus just referencing Attachment 1 does not address Xcel's request.</p>
Ameren	<p>(a) R3 - nalyze disturbance on GOP system is unclear or vague. Drafting team should describe what is expected.</p> <p>(b) R3.1 - "analyze performance of their equipment" is vague. Drafting team should describe what is expected or delete the requirement.</p> <p>(c) A.5. Effective date - Most entities revise procedures on an annual basis. having an effective date that is less than a year away might result incremental, hastily developed procedures. If the effective date was the first day of the first calendar year after approval, it is likely no extra reviews/update would be necessary.</p>
Northeast Power Coordinating Council	<ol style="list-style-type: none"> 1. There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. 2. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. 3. The RC and BA, responsible for analysis, most likely do not own much in the way of systems or facilities except for back-up facilities. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 4. The new standard language in R3 and 3.1 suggests that any disturbance originating from outside of the applicable Registered Entity will have to be reported and there are no means for how the reporting is to be handled. 5. Why wasn't DP added to R4?
E.ON U.S.	<p>In paragraph 612, FERC says to “consider the concern...in future modification”, not to actually change requirements. The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive. The performance of GO, DP or LSE equipment may not be required to analyze BES disturbances. Information should be provided only if it is requested, or if the GO, DP or LSE BES equipment malfunctioned. Simply requiring GO, DP or LSEs to in all instances provide information on their equipment performance does not improve reliability and adds unnecessary administrative and compliance obligations.</p> <p>In paragraph 615, FERC says to “consider the comments...in future modification”, not to actually change requirements.</p> <p>The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive. It is unclear how the insertion in R4 clarifies the definition of a reportable “event” as the standard references a reportable “incident.”</p>
Florida Municipal Power Agency	<p>In Paragraph 615, the changes made to the standard do not address the concern: "Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is</p>

Organization	Question 16 Comment
	<p>for each entity that has reporting obligations."</p> <p>Attachment 1 should be modified to define which Functional Entity needs to report which reportable event. It is still quite ambiguous who has to report what. For instance, a Distribution Provider would certainly not have to report an islanding event, yet, it is possible to interpret it that way.</p>
National Grid	<ul style="list-style-type: none"> o There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. o These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. o The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o There is inconsistency in requirements R3 and R4 with respect to "Distribution Provider". R3 includes DP while R4 does not. National Grid suggests including Distribution Provider in R4. o Who is responsible for reporting when DP is analyzing the disturbances? National Grid suggests that DP should be listed in Attachment 1.
Southern Company Transmission	<p>Paragraph 612 - Suggest removing the 'At a minimum' phrasing at the beginning of R3.1 as it does not add any clarity. We don't believe the VSL being based on percentages is the best approach. The number of reportable events will likely be small. Instead of trying to construct one VSL, the VSLs for the entire standard should be undertaken at once.</p> <p>There should be a concern that generator operators, DP's and LSEs may be unable to promptly analyze BES disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis.</p> <p>Paragraph 615 - Not low hanging fruit.</p>
American Electric Power	<p>Paragraph 612 There appears to be no benefit of having R3 and R3.1 as separate requirements. AEP suggests the two requirements be combined into one requirement as follows,</p> <p style="padding-left: 40px;">"R3. Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities and provide this information to its associated Reliability Coordinator, Balancing Authority, and Transmission Operator."</p> <p>Paragraph 615 R4 needs to include the Distribution Provider since it was added to R3.</p> <p>The VSL for the proposed R3 is not consistent in severity with the existing VSL for R2. Under the current standard, each Generator Operator and Load Serving Entity is required to promptly analyze BES disturbances per R2 and its associated VSL. The proposed</p>

Organization	Question 16 Comment
	<p>standard moves the GOP and LSE requirements to a new requirement, R3. A VSL was established for R3, but the VSL for R2 was not revised. Per the proposed standard, failure of the Generator Operator to promptly analyze greater than 15% of its disturbances on the BES would result in a Severe VSL. However, using the existing R2 VSL, a Transmission Operator who fails to promptly review 1% to 25% of its disturbances on the BES would only be subjected to a Moderate VSL.</p> <p>The VSLs should be revised to allow for consistency between the R2 and R3 VSLs, and correspond with what has already been established for the TOP.</p> <p>Additionally the VSL for R2 in the current standard should be revised to remove reference to the Generator Operator.</p> <p>The last sentence of Measures M2 and M3 each need to be revised to reference Requirements 4.1 and 4.3, respectively.</p>
Oklahoma Municipal Power Authority	Paragraph 615: Attachment 1 should be revised to clarify which Functional Entities are responsible for each type of reportable event.
CECD	<p>Question 1: APPA's concerns appear to be with the inability to perform an analysis of a disturbance that originated outside of their system and with coordination between affected registered entities. The standard already specified that the registered entity must only perform an analysis of disturbances on "its system or facilities" so no modifications were required to address this issue. The second issue identified by APPA seems to be the coordination between affected parties. The proposed language in R3.1 partially addresses this issue by requiring coordination (information sharing) by the GOP, DP and LSE with their associated RC, BA, and TOP, however the RC, BA and TOP should also be required to share information with impacted entities.</p> <p>Question 2: If the intent of including the reference to Attachment 1 in R4 was to assist in defining a Reportable Event the parenthesis should be directly after the phrase "reportable incident" and "reportable incident" should be changed to "Reportable Event".</p>
US Bureau of Reclamation	The generator operators in WECC provide disturbance reports to WECC. The new requirement provides the information to TOP, BA, and RC. This standard requires far too many reports. Reports are sent to WECC, NERC, DOE and now the TOP and BA. It is not clear what benefit will be derived by this redundant requirement. The requirement should be limited to analyzing the events and providing reports upon request. WECC already has a disturbance reporting and analysis process to ensure BES issues are addressed. In addition the entities must analyze protection system operations in PRC-004. It is interesting that the Commission continues to ensure unilateral communication among the entities by not requiring TOP and BA to share their disturbance reports with the GOP, DP, and LSE's.
United Illuminating Company	United Illuminating does not believe the VSL is properly descriptive. It lists the severity level based on a percentage of events not analyzed. What is the time period being considered? In a calendar year, in a three year audit period?
Midwest ISO Standards Collaborators	We suggest the parenthesis within the requirement should be removed from around the reference to the attachment. We don't believe that the changes address Xcel's concern expressed in the directive. We believe Xcel wanted more details for the specific functional entities. Furthermore, the directive did not state that the Commission believed that Xcel's concerns regarding the WECC process should

Organization	Question 16 Comment
	<p>be handled through a variance as stated in NERC’s comments. As a result, we do not believe the directives in paragraph 615 are fully addressed.</p> <p>Adding sub-requirement 3.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
<p>NERC Standards Review Subcommittee</p>	<p>#15. The word “promptly” is used within R2 and R3 but not R3.1. Recommend that the word “promptly” be deleted from these requirements. During any system disturbance the RC, BA or TOP will be focusing on mitigating the disturbance, then reporting of the disturbance (as outlined in the standard) and then start to investigate the cause of the disturbance. When promptly is used and entity may investigate prior to reporting which may lead to a non compliance situation.</p>
<p>Georgia System Operations Corporation</p>	<p>15) In EOP-004 R3.1 the introductory words “At a minimum” imply that more action than stated might be needed to be compliant but the requirement does not elaborate on what additional steps might be required. “At a minimum” adds nothing to the requirement except ambiguity and should be deleted. FERC never said that we have to take the exact wording from their order and insert it into the standard. The ambiguity is compounded by structuring R3 as a requirement and sub requirement. We recommend deleting R3.1 and rewriting R3 as follows:</p> <p style="padding-left: 40px;">Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze the performance of its equipment in reacting to a Bulk Electric System disturbance on its system or facilities and provide the results of its analysis to its Reliability Coordinator, Balancing Authority, and Transmission Operator.</p> <p>Also, as a general statement this standard refers to Regional Reliability Organization instead of Regional Entity.</p> <p>The Measures refer to Requirements R3.1 and R3.3. We believe they should refer to R4.1 and R4.3 now.</p>
<p>Consumers Energy Company</p>	<p>Comments: It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of “disturbance investigations” annually, the vast majority of which have no impact.</p> <p>Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern.</p> <p>It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating</p>

Organization	Question 16 Comment
	<p>personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report.</p> <p>Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance.</p> <p>Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006.</p> <p>Please provide your opinion regarding the Paragraph 612 VRF and VSLs: Opposed Comments: It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of “disturbance investigations” annually, the vast majority of which have no impact. Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern. It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report. Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance. Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006.</p>
Kansas City Power & Light	<p>Directive 612: Do not believe the proposed changes addresses the concerns of APPA as recognized by the Commission. The proposed requirements direct the Generator Operators and Load Serving Entities to “promptly analyze Bulk Electric System disturbances on its system or facilities” in R3 which APPA has a direct concern. Recommend modifying the requirement R3 and sub-requirement R3.1 to state that Generator Operators and Load Serving Entities provide data available from installed data recording systems, if they exist, upon request of other TOP’s or BA’s.</p>
Illinois Municipal Electric Agency	<p>It is not clear in R3.1 how an entity is to “provide”. Why not just add DP to R4 as one of the reporting entities, and add RC, BA, and TOP to R4 as also receiving the preliminary written report?</p>
Santee Cooper	<p>Paragraph 612 -The proposed changes do not appear to address the Commission’s directive. We suggest a new requirement should be “Following a disturbance and at the request of a RC, BA or TOP, a GO, DP or LSE shall promptly analyze the performance of their</p>

Organization	Question 16 Comment
	equipment and provide all requested information necessary to analyze BES disturbances.”
Western Electricity Coordinating Council	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague. Promptly needs to be clarified, considering different time frames for different types of events.

17. Do you believe the changes made in response to the directive(s) contained in Paragraph 693 of Order No. 693 are both valid and address the directive(s)?

693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	FAC-002-1	Modified Section B Requirement R1.4
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Organization	Yes or No
E.ON U.S.	No
Xcel Energy	No
Consumers Energy Company	No
Kansas City Power & Light	No
ERCOT ISO	No
US Bureau of Reclamation	No
Midwest ISO Standards Collaborators	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes

Organization	Yes or No
Dynergy Inc.	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SDG&E	Yes
SERC OC Standards Review Group	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

Organization	Yes or No
Georgia System Operations Corporation	Yes
Southern Company Transmission	Yes

Comments on the FAC-002 Standard Changes

Summary Consideration:

The majority of commenters agree with the proposed changes.

Some commenters expressed a concern that by making a reference to the TPL standards, the Responsible Entities for the FAC-002 standard will be subject to having to also comply with the referenced TPL standards. The Response Team holds the view that this already exists within the original language of the standard via its reference to TPL-001. The Response Team does not think that in general, referencing another standard will subject the entities listed in the Applicability Section to be also held responsible for complying with the referenced standard. We encourage stakeholders to work to improve this standard in its next version.

Some commenters suggest removing the wording “under both normal and contingency conditions” from Requirement R1.4. The Response Team has not adopted the suggested change since the proposed wording in R1.4 adopts the same wording indicated in the directive. We do not see the added value by adopting the commenters’ proposed alternative wording. Nonetheless, we thank the commenters for their suggestion.

Organization	Question 17 Comment
IRC Standards Review Committee	<p>Paragraph 693 Taken in isolation the proposed change to R2 is appropriate. In the context of the entire requirement, the proposed change raises an issue that make this seemingly trivial request more complex than the requestor makes it out to be.</p> <p>o The proposed change is a change to a sub requirement to R1. However, R1 is not well designed as a mandatory standard. R1 includes multiple applicable entities, and requires that those entities all “coordinate and cooperate”. The latter terms are not defined, not measured and confusing as it applies to compliance.</p> <p><i>Response: This scope of this project is to implement changes as indicated in the directives. The project does not include improving the quality of the entire standard. However, your comment will be retained for future consideration when this standard is due for revision.</i></p>
Consumers Energy Company	<p>Comments: Of the six applicable entities on FAC-002, only two are applicable entities under the TPL standards (Transmission Planner and Planning Authority/Coordinator, depending on the Functional Model terminology). The reference to the TPL standards in R1.4, which addresses ONLY the other four entities, makes those entities indirectly subject to the TPL standards, which are irrelevant to those entities.</p> <p><i>Response: The Response Team does not share your view that the Responsible Entities for the FAC-002 standard will be subject to having to also comply with the referenced TPL standards. The Response Team does not think that in general, referencing another standard will subject the entities listed in the Applicability Section to be also held responsible for complying with the referenced standard. We encourage the commenter to work to improve this standard in its next version.</i></p>
Kansas City Power & Light	<p>Directive 693: The Violation Severity Levels for R1.4 do not reflect the additional references to Standards TPL-002-0 and TPL-003-0 as</p>

Organization	Question 17 Comment
	<p>included in the proposed change for R1.4.</p> <p>Response: The VSLs for R1 of FAC-002 do not make specific reference to the details contained in each of the subrequirements. We do not see any inconsistency that warrants the need for changing the VSLs.</p>
ERCOT ISO	<p>Q17 - The proposed language certainly addresses the directive, but all that was needed was to reference TPL-002 and TPL-003. ERCOT ISO suggests the following wording for R1.4:</p> <p style="padding-left: 40px;">“Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.”</p> <p>Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.</p>
US Bureau of Reclamation	<p>The requirement cites TPL-001 through 003 which do not apply to GO's. The modification makes matters worse in that the GO is now required to analyze system performance under contingency conditions. This is normally performed by the TP.</p> <p>Response: This obligation to conduct studies exists in the current standard. The proposed changes serve to clarify an aspect of the scope of studies only. We do not see this change has any material impact on the individual Responsible Entities' obligations.</p>
Midwest ISO Standards Collaborators	<p>We believe “under normal and emergency contingency conditions” should be struck from the additions. TPL-001, TPL-002 and TPL-003 already identify normal and emergency conditions through the Table C requirements. We believe the clause only adds confusion. Furthermore, the Commission did not request the clause to be added but requested the reference to TPL-001, TPL-002 and TPL-003 to be added “to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.”</p> <p>Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.</p>
Georgia System Operations Corporation	<p>None.</p>
Southern Company Transmission	<p>Paragraph 693 - The Commission did not request the clause to be added but only requested the reference to TPL-001, TPL-002 and TPL-003 to be added “to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.”</p> <p>Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.</p>

18. Do you believe the changes made in response to the directive(s) contained in Paragraph 1249 of Order No. 693 are both valid and address the directive(s)?

1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican’s observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel’s proposal that the standard be revised to include only the generic term “peak producing weather conditions” because it is too generic for a mandatory Reliability Standard.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
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Organization	Question 18
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 18
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Pepco Holdings, Inc. - Affiliates	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Western Electricity Coordinating Council	No
CECD	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes

Organization	Question 18
Springfield Utility Board	Yes
United Illuminating Company	Yes
Xcel Energy	Yes

19. Do you believe the changes made in response to the directive(s) contained in Paragraph 1250 of Order No. 693 are both valid and address the directive(s)?

1250	We also reject Alcoa’s proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa’s concerns in its Reliability Standards development process.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
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Organization	Question 19
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 19
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Western Electricity Coordinating Council	No
Xcel Energy	No
CECD	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes

Organization	Question 19
Pepco Holdings, Inc. - Affiliates	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes

20. Do you believe the changes made in response to the directive(s) contained in Paragraph 1251 of Order No. 693 are both valid and address the directive(s)?

1251	<p>The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.</p>	MOD-017-1	<p>Added Section B Requirement R1.5. Modified VSLs for R1.</p>
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Organization	Question 20
Ameren	No
American Electric Power	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 20
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Xcel Energy	No
Arizona Public Service Company	Yes
CECD	Yes
Indiana Municipal Power Agency	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes

Organization	Question 20
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

21. Do you believe the changes made in response to the directive(s) contained in Paragraph 1252 of Order No. 693 are both valid and address the directive(s)?

1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	MOD-017-1	Added Section B Requirement R2. Added Measure M2 and VSLs for R2.
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Organization	Question 21
Ameren	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No

Organization	Question 21
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
United Illuminating Company	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Florida Municipal Power Agency	Yes
Illinois Municipal Electric Agency	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes

Organization	Question 21
Western Electricity Coordinating Council	Yes

22. Do you believe the changes made in response to the directive(s) contained in Paragraph 1255 of Order No. 693 are both valid and address the directive(s)?

1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	MOD-017-1	Added Section A 4.4 (Transmission Planner). Modified Section B Requirement R1 and R2. Modified Measure M1.
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Organization	Yes or No
Xcel Energy	No
IESO	No
Santee Cooper	No
Ameren	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
National Grid	No
Oklahoma Municipal Power Authority	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No
Southern Company Transmission	No

Organization	Yes or No
CECD	Yes
Springfield Utility Board	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
Georgia System Operations Corporation	Yes
Consumers Energy Company	Yes
Arizona Public Service Company	Yes
SDG&E	Yes
American Electric Power	Yes
ERCOT ISO	Yes
Indiana Municipal Power Agency	Yes
PacifiCorp	Yes
Western Electricity Coordinating Council	Yes
United Illuminating Company	Yes
Pepco Holdings, Inc. - Affiliates	Yes
E.ON U.S.	Yes

Comments on the MOD-017 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1249, P1250, P1251, P1252, and P1255 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 22 Comment
Central Lincoln	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or if many (how many?) readings are to be averaged. And why does the entity that has a variation on temperature but not humidity, still need to report humidity?
IRC Standards Review Committee	<p>Paragraph 1249 & 1250 The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons:</p> <ol style="list-style-type: none"> 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA’s varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC’s claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research

Organization	Question 22 Comment
	<p>but not a good reason to mandate data.</p> <p>5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.</p> <p>Paragraph 1251The proposed changes to R1.5 are confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision.</p> <p>Paragraph 1252 & 1255There are several issues with the accuracy proposal:</p> <ol style="list-style-type: none"> 1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to “every other” LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Illinois Municipal Electric Agency	<p>What will this additional data reporting accomplish? Has a problem been identified with the current MOD-017 reporting that needs to be resolved? If so, it has not been communicated. These proposed revisions need further vetting to adequately assess the need and the impact on entity resources, particularly small entity resources.</p>

Organization	Question 22 Comment
IESO	<p>(1) We do not agree with the changes to R1.2, in particular the second sentence which asks for weather data which is redundant with that already provided in R1.1.</p> <p>(2) Specific to the proposed changes to address the directive in Paragraph 1251, R1.5 is confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. Is it operator adjustments? If so, isn’t forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires “value-added” actions by the forecaster. Biasing is not a defined term. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision. Further, day-ahead hourly for each hour is not clear. This could represent a large number of forecasts (if multiple day ahead forecasts are made).</p> <p>(3) Specific to the proposed changes to address the directive in Paragraph 1252, we question the basis for the 10% error if used as a threshold for R2. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review its forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not. In addition, the word “load” should be Capitalized throughout in R2 and M2.</p>
Santee Cooper	All Paragraphs - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Ameren	All referenced requirements need to explicitly address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Kansas City Power & Light	Directives 1251, 1252, and 1255: Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be

Organization	Question 22 Comment
	subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Florida Municipal Power Agency	<p>In Paragraph 1251, load forecasting in the planning horizon is performed using a different method and a different purpose than load forecasting in the operating horizon. The MOD standards do not require a Day-ahead hourly forecast, the operating horizon standards do. Hence, Day-ahead hourly load forecasts should not be included in MOD-017 and R1.5 should be modified to remove Day-ahead Hourly for each hour since only monthly and annual peak loads are being forecasted in R1.3 as part of the planning horizon efforts.</p> <p>In Paragraph 1255, Transmission Planners should not be responsible for load forecasting and hence should not be applicable to this standard. Transmission Planners simply gather the load forecasts of the entities responsible for load forecasting within their planning area. In essence, a Transmission Planner will be dependent on the compliance of the entities within its planning area to remain compliant. If that is the case, then, there should be multiple requirements making entities within the planning area report load forecasts to the Transmission Planner before the Transmission Planner is enabled to report a load forecast to the region. This additional layer of administrative burden makes no sense. If Transmission Planners develop different, independent load forecasts, which ones will be used in the regional analyses? Those provided by the TPs, or the aggregate of those provided by other entities within the TPs planning area? The FERC directive can probably be addressed through a requirement of the Region to break out the regional load forecast by each Transmission Planning area.</p>
National Grid	<ul style="list-style-type: none"> o In requirement R1.1, the location of the reading for coincident hourly temperature and humidity is not clear. Also, in National Grid, the record keeping is done on aggregate basis and not on daily basis. The data is taken from weather services and it is not an automatic process of data collection. o In Requirement 1.5, is the load on a system basis or on a substation/bus basis? What is meant by “biasing of each load forecast”? Is this applicable to Demand Response? Also, “day-ahead hourly” does not add any value from a Planning perspective since it is a market/operations issue. o With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL. o National Grid believes that the Planning Authority has the authority to collect information and hence the information collection should be retained at the level of Planning Authority and not include Transmission Planner. o General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. o General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o General comment - Each entity’s expertise should be relied upon to gather the appropriate weather information.
Oklahoma Municipal Power Authority	Paragraph 1251: Remove Day-ahead hourly forecasts from R1.5 to be consistent with the rest of the standard; specifically,

Organization	Question 22 Comment
	<p>R1.3.</p> <p>Paragraph 1255: Transmission Planners should not be responsible for load forecasting. Load forecasting is completed by other entities and submitted to Transmission Planners.</p>
<p>Dominion</p>	<p>Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below:</p> <ol style="list-style-type: none"> 1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. 2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing) models. 3. R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. 4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
<p>Entergy Services</p>	<p>Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service</p>

Organization	Question 22 Comment
	<p>Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models. R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable.</p> <p>We suggest that R2 should be given to a standards drafting team to develop appropriately.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.</p>
SERC OC Standards Review Group	<p>Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing) models.-</p> <p>R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or</p>

Organization	Question 22 Comment
	enhance reliability.
Midwest ISO Standards Collaborators	<p>While the proposed changes may meet directives in paragraph 1249 and 1250, we do not believe this represents the solution that is needed.</p> <p>For one, there is no clear or apparent use of the data being supplied. If the data is to gauge the accuracy of load forecast, FERC already directed the ERO to write other requirements to assess accuracy.</p> <p>Secondly, the requirement does not indicate what data is to be supplied. Is it the data that the entity uses for input into their load forecast model? Is it the data for every major city?</p> <p>Thirdly, each load forecast is highly dependent on the model being used. While some entities may use dozens of locations for weather input others may not.</p> <p>Thus, any effort to normalize load to weather will be dependent on the process/model that the ERO or the Region Entity is using. The data supplied may not match the needs of the ERO or Regional Entity. Because this information is so readily available, it only makes sense for the ERO and Regional Entities to gather the information from an appropriate commercial service to ensure the data meets their needs.</p> <p>We disagree with the proposed changes to address directives in paragraph 1251. While they may technically meet the directive because the wording from the directive was essentially inserted as a sub-requirement, we do not believe that the requirement is clear or represents the best solution. For instance, what is biasing in a load forecast? Additionally, the Commission did not state what load forecast error should be compared. For example, LSEs will have dozens of load forecasts for the same time period that are updated with newer weather information as the operating hour approaches. Why was Day-Ahead selected? Why not seven days ahead? 12 hours ahead, etc.? We believe this directive does not represent low-hanging fruit that can be addressed in an ad hoc manner such as this SAR. Further, because load forecasting is a complicated process, we believe it is necessary to retain a group of load forecasting experts in a drafting team to address these directives appropriately so that meaningful requirements can be written.</p> <p>We disagree with R2 that is intended to address the directives in paragraph 1252 and 1255. An LSE is constantly updating and tuning their load forecast model and cannot tolerate a load forecast error anywhere close to 10%. If an LSE only reviewed their load forecast annually and adjusted the inputs if the error exceeded 10%, there are many days each year that the LSE would likely not serve load. This requirement represents a significant reduction in reliability. A group of load forecasting experts needs to be convened in a drafting team to address this directive.</p> <p>Adding sub-requirements R1.5 and modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a</p>

Organization	Question 22 Comment
	<p>standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
<p>Southern Company Transmission</p>	<p>While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models. R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary.</p> <p>Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p> <p>While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.</p>
<p>NERC Standards Review Subcommittee</p>	<p>#21. R2 states that as an example, variation expressed in terms of error divided by actual demand is greater than 10%. The 10% threshold is not defined by FERC in its Order and request that a basis be given prior to supporting the proposed changes. Overall R2 does not enhance reliability of the BES. R2 states that the applicable entity annually reviews the previous year’s load forecast for 10% variation and if necessary modify load forecast assumptions to improve accuracy. It is unclear if the improved assumptions are to be used for the previous year or the upcoming year? If for the upcoming year, than it must be clearly stated that the responsible entity is to apply last year assumptions to next year’s forecast.</p>
<p>Northeast Power Coordinating Council</p>	<ol style="list-style-type: none"> 1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.

Organization	Question 22 Comment
	<p>3. General comment - Each entity's expertise should be relied upon to gather the appropriate weather information.</p> <p>4. In Requirement R1.5 - What is meant by "biasing of each load forecast"?</p> <p>5. With respect to Requirement R1.5 - Is this applicable to Demand Response?</p> <p>6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error.</p> <p>7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed.</p> <p>8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.</p>
Georgia System Operations Corporation	<p>18a) MOD-017 R1. It is not clear what temperature and humidity data to use. We believe this data collection would actually serve to confuse rather than enhance reliability. If the requirement remains, recommend removing the "if" clause and simply stating to supply temperature and humidity data.</p> <p>18b) MOD-017 R2. It is not clear when an entity is required to modify its load forecast assumptions. The use of the abbreviation e.g. (which means "for example") implies that there are other situations which would require modification of the forecast assumptions, but we are given no guidance as to what they might be. The 10% seems to be an arbitrary value as well. Utilities, as good business practice, seek to have the best forecast possible and its inherent to their own interests to either improve their process or replace the model as needed. We recommend the requirement should be rewritten as follows:1</p> <p>8c) The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its Load forecast process to improve accuracy as necessary.</p> <p>18d) Otherwise, if there are other conditions that would require that assumptions be modified those conditions must be clearly stated in the standard. Entities have a right to a clear statement of what they are required to do and when they are required to do it. Sometimes assumptions are correct, and extreme conditions occur. It does not necessitate that your assumptions should change for the next year.</p> <p>20) MOD-017 R1.5. It is not clear as written. At a minimum, we recommend removing the daily granularity for reporting of hourly load forecast error.21) The VSL's should remove the "e.g." language.</p>
Consumers Energy Company	<p>Changes for directives in Paragraph 1249: Approve Please provide your opinion regarding the Paragraph 1249 VSL changes: In Favor Changes for directives in Paragraph 1250: Approve</p> <p>Please provide your opinion regarding the Paragraph 1250 VSL changes: In Favor Changes for directives in Paragraph 1251:</p>

Organization	Question 22 Comment
	<p>Disapprove Comments: R1.5 includes a requirement for "Day-ahead Hourly . . . load Forecast accuracy . . .". This seems to exceed the focus of the Order, which is oriented toward planning. Additionally, the standard is not clear what is intended by "day-ahead" forecast. There often are multiple "day-ahead" forecasts, as weather forecasts change and current day load patterns emerge. Finally, the text appears to capitalize terms that are not defined in the Glossary. Please provide your opinion regarding the</p> <p>Paragraph 1251 VSL changes: In Favor Changes for directives in Paragraph 1252: Disapprove 44) Comments R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.45)</p> <p>32. Please provide your opinion regarding the Paragraph 1250 VRF and VSLs Opposed 46) Comments R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.</p>
Arizona Public Service Company	<p>For both Question 18 and 19, AZPS does not agree with how NERC has revised the standard to comply with Order 693. Our reading is that FERC is requesting temperature and humidity readings for the peak load, interpreted as Peak Day. The Standard as proposed is over-reaching as it requires weather data for each and every hour of every day (8760).</p>
SDG&E	<p>Paragraph 1249, Proposal is cumbersome and problematic in term of accurate regional weather normalization. Alternative approach: direct each entity to provide its own estimate of weather-normalized load (instead of providing raw data on hourly temperature and humidity).</p> <p>Paragraph 1250, Requirement 1.1 and 1.2; (Issue: ALCOA proposal). Suggested Reporting of weather data should not be required for entities whose entire load is not weather-sensitive.</p>
American Electric Power	<p>Paragraphs 1249 & 1250The proposed change in MOD-017 R1.1, "for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year" does not support reliability for the following reasons:</p> <ol style="list-style-type: none"> 1. It is unclear what reliability objective is being served. If this data is for NERC to analyze and verify peak load data used by Registered Entities for operations, then the weather across Registered Entities varies too greatly to provide one set of coincident numbers and would provide little benefit. What reliability benefit would there be to add a requirement for sending information that will not be used? This would be an inefficient use of resources, which could instead be used for supporting other reliability objectives. 2. Whether or not the load data is sensitive to weather is a matter of importance for the local planners, but not for planners who

Organization	Question 22 Comment
	<p>report wide-area assessments to NERC.</p> <p>3. NERC through its Rules of Procedure has the ability to collect the information when necessary.Paragraph 1251With respect to MOD-017 R1.5, we do not see the benefit to include the day-ahead forecast accuracy to NERC and the Regional Entities.</p>
ERCOT ISO	<p>Q18 - The language does seem to address the directive, but is likely to be controversial as it goes directly to telling how to do something rather than what needs to be done to ensure reliability. This standard needs to be fully vetted with the industry through the standards development process in order to refine the requirements from the current language to properly address the directive. These changes cause ambiguity.</p> <p>Q19 - See Q18 comments immediately above.</p> <p>Q20 - The proposed language requires reporting, but it does not address the temperature and humidity variations. Again, this language gets into details of how to do something rather than what must be done. This change causes ambiguity.Q21 - The proposed language appears to address the directive, but ERCOT ISO disagrees with the added parenthetical language. Furthermore, ERCOT ISO disagrees with the phrase 'if necessary' because it introduces ambiguity.</p>
Indiana Municipal Power Agency	<p>Question 18 - The Commission is not requiring that the coincident hourly temperature and humidity data be recorded for the prior year (for each load hour, peak and off peak). It is IMPA's belief that the way this current requirement is written goes beyond teh Commission directive and is creating an undue burden on entities. IMPA does agree that collecting the day's temperature high and low temperature, along with the day's humidity (or just the peak period humidity), meets this directive and should be recorded for weather normalization of the peak load. The collecting of off-peak hourly weather data is not useful and is wasteful.</p> <p>Question 21 - The high VSL includes the for example wording "variation was greater than 10%". If this is truly for example only, it should be removed from the VSL which will eliminate teh influence of an example statement in the enforcement of the high VSL for requirement 2.</p>
PacifiCorp	<p>Request addition implementation time since this standard is not related to reliability improvements. These upgrades will require significant software and system changes and may require upgrades in technology to allow interactive communication with other utilities.</p> <p>R1.1 Current wording "For loads that vary based on temperature and/or humidity..." is vague-all of PAC loads could fall under this criteria. What kind of granularity is appropriate-entire BA????</p> <p>R1.5 Internal comment-New language "Day-ahead Hourly, Monthly Peak hour..." hourly is significantly more detail than current processes.If the new language requires accuracy ("...expressed in terms of error divided by actual demand) as well as any biasing of each load forecast..."), will this have any impact on spot purchasing process? Rephrase the language as follows since we base our analysis on average daily temperature. For Loads that vary based on temperature and/or humidity,</p>

Organization	Question 22 Comment
	temperature and humidity data for the prior year used to normalize demands.
Western Electricity Coordinating Council	<p>Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions:</p> <p>1) Would average data then be required? or</p> <p>2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?.</p> <p>Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 (redundant). An alternative to actually submitting the coincident hourly temperature and humidity data is to require the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.</p>
United Illuminating Company	<p>United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix. UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated. The Standard requires two Load Forecasts a two year monthly (R1.3) and as requested a five to ten year forecast (R1.4). It is unclear which forecast is being addressed in R2.</p>
Pepco Holdings, Inc. - Affiliates	<p>While the changes address the directives, there is no real need for this kind of data beyond what is already used in planning. We fervently hope this is removed when the full standard is reviewed in the normal process.</p>
E.ON U.S.	<p>With respect to paragraphs 1249 & 1250, FERC directs submittal of temperature and humidity. The proposed revisions go beyond what is directed by FERC by adding temperature sensitive loads to the requirements.</p> <p>In paragraph 1251, FERC directive allows adjustment for temperature and humidity variations while the proposed revisions to R1.5 does not allow this adjustment. In addition, the term "biasing" is introduced, but is not discussed nor defined with respect to load forecasting.</p> <p>With respect to paragraph 1252, FERC did not specify how to correct forecasts. NERC should assemble a drafting team to develop reasonable criteria for correcting potential forecast error based on historic inaccuracies.</p>

23. Do you believe the changes made in response to the directive(s) contained in Paragraph 1276 of Order No. 693 are both valid and address the directive(s)?

1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission’s concern.	MOD-019-1	Modified Section B Requirement R1.
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Organization	Question 23
Ameren	No
Arizona Public Service Company	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
Florida Municipal Power Agency	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No

Organization	Question 23
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Pepco Holdings, Inc. - Affiliates	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Springfield Utility Board	No
Xcel Energy	No
American Electric Power	Yes
CECD	Yes
ERCOT ISO	Yes
Georgia System Operations Corporation	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes

Organization	Question 23
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

24. Do you believe the changes made in response to the directive(s) contained in Paragraph 1277 of Order No. 693 are both valid and address the directive(s)?

1277	We direct the ERO to include APPA’s proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	MOD-019-1	Added Section B Requirement R2. Added VSLs for R2.
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Organization	Yes or No
Xcel Energy	No
NERC Standards Review Subcommittee	No
IESO	No
Ameren	No
Northeast Power Coordinating Council	No
Santee Cooper	No
Arizona Public Service Company	No
Consumers Energy Company	No
Kansas City Power & Light	No
E.ON U.S.	No
Florida Municipal Power Agency	No
SDG&E	No
Oklahoma Municipal Power Authority	No

Organization	Yes or No
Georgia System Operations Corporation	No
National Grid	No
Southern Company Transmission	No
SERC OC Standards Review Group	No
Dominion	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
American Electric Power	No
Springfield Utility Board	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
Entergy Services	No
CECD	Yes
Illinois Municipal Electric Agency	Yes
Western Electricity Coordinating Council	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes

Comments on the MOD-019 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1276 and P1277 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Yes or No	Question 24 Comment
IRC Standards Review Committee		<p>Paragraph 1276 Taken in isolation the general nature of the proposed change to R1 is appropriate. In the context of the details of the requirement, the proposed R1 changes raise issues regarding: the lack of clarity in definition of what DCLM is; what biases (see R1.2) it wants and who needs what information for reliability. The SAR requestor does not recognize the fact that the ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. The question is “what is the reliability-need to analyze LSE load data when the PA’s data is the only relevant data for use in Planning Assessments”? Localized modeling may also use localized loads but that would be on a bus load basis not on an entity basis.</p> <p>Paragraph 1277 Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.</p>
NERC Standards Review Subcommittee	No	<p>#24. Please provide a basis for the 10% threshold since FERC did not state this in Order 693. Not sure how modifying load forecast assumptions to improve accuracy will benefit the BES unless the applicable entity applies it to the upcoming forecast. Short term forecasts can be off by more than 10% due to uncontrollable weather and long term forecasts can be off due to unforeseen economic conditions such as the 2008 / 2009 recessions. A zero DSM period could occur due to an unforeseen conditions making any forecast compared to zero more than a 10% error. Further DSM can be a very small portion of an overall forecast. Mandating a correction and applying a high VSL to future forecasts for events beyond an entity’s control (especially when the possibility of zero exists), i.e when an entity “failed to make improvements to improve accuracy”, is unrealistic.</p>

Organization	Yes or No	Question 24 Comment
IESO	No	<p>(1) Specific to the proposed changes to address the directive in Paragraph 1276, we generally agree with the changes to R1.</p> <p>(2) Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review its forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not. And does the load forecast mean Load forecast peak MW demand, peak hour energy demand, minimum demand, or all of the above? In addition, R2 is added without a corresponding M2. And why is Forecast (not a defined term) capitalized in R1.2 but not so elsewhere? Should interruptible demands be interruptible Loads?</p>
Ameren	No	(a) R1.1 - Add ",DSM," after interruptible demands (b) R2 - what is the basis for 10%?
Northeast Power Coordinating Council	No	<ol style="list-style-type: none"> 1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R1.2 - How about simply 'Summer and winter peak actual and weather corrected peak if observed, forecast load (one year ahead).' This requires provision of the weather corrected actual which is directly comparable to the forecast. What is meant by "biasing of each load forecast"? 4. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 5. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 6. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.

Consideration of Comments on Project 2010-12 — Order 693 Directives

Organization	Yes or No	Question 24 Comment
Santee Cooper	No	All Paragraphs - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Arizona Public Service Company	No	AZPS agrees that the changes to R1 address Paragraph 1276 in Order 693. However, during the change process NERC has changed R1 to have sub-requirements R1.1 and R1.2. In doing so NERC has changed the meaning of R1. Prior to the change, R1 stated that annually as requested. Now the Standard states that the information shall be provided annually, yet R1.1 states as requested. This should be clarified to remove any confusion. Requirement R2 should be revised to state "... shall annually review the controllable load forecast ...". Order 693 direction is for controllable forecast, not Load forecast.
Consumers Energy Company	No	<p>Changes for directives in Paragraph 1276: Disapprove Comments: As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand?</p> <p>Changes for directives in Paragraph 1277: Disapprove Comments: As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? R2 (and therefore the VSL) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.</p>
Kansas City Power & Light	No	Directives 1276 and 1277: Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R1.2 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load forecasting groups to "compare" actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit. It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted

Organization	Yes or No	Question 24 Comment
		<p>load information as defined in this Standard MOD-019. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.</p>
E.ON U.S.	No	<p>In paragraph 1276, FERC does not specify a five year minimum forecast period. The proposed revised standard does not identify the basis for the five year minimum. The time period for reporting may be covered in MOD16-1 R1 and may create conflicting requirements based upon time periods for data submittal. E ON U.S. suggests R1.1 be edited to read:</p> <p style="padding-left: 40px;">“Forecasts of interruptible demands and Direct Control Load Management (DCLM) as contained in the documentation for MOD16-1for summer and winter peak system conditions.”</p> <p>Regarding paragraph 1277, R2.2 should specify differences in controllable load. R2,2 also omits FERC directive to use five years of actual variations to improve the ten year forecast.</p>
Florida Municipal Power Agency	No	<p>In Paragraph 1276, this directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task. In Paragraph 1277, This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.</p>
SDG&E	No	<p>Issue:The language in MOD-019 is too broad in Requirement 2 - a new requirement for this standard. While the purpose of the standard is to focus on a forecast for Demand Response and DCLM, Requirement 2 states forecast without being specific.</p> <p>Second, the requirement also only allows for a 10% variance from forecast to actual, and we believe that in most years we will have a variance beyond the 10%, thus forcing us to develop a method to be closer to our forecast. Assuming that we have a weather anomaly, for which we have NO control, we would be unable to develop a method to stay within the 10% variance. We could also experience an Earthquake, or a fire, both of which will also be beyond our control. In the alternative, we should only have to develop an answer as to WHY our forecast was beyond the 10%</p>

Organization	Yes or No	Question 24 Comment
		<p>variance, and we should not have to develop a method to put us closer to our forecast.</p> <p>We may also want to suggest that NERC is confusing a planning forecast with an operating forecast, which are two separate environments.</p>
Oklahoma Municipal Power Authority	No	It is not clear how the requirements in R2 are to be accomplished.
Georgia System Operations Corporation	No	<p>Mod-019 R2. This requirement is a virtual copy of Mod-017 R2 and as written does not address FERC's directive. We believe the intended distinction between the two is that MOD-019 R2 should be focused on interruptible load. If so, it should be rewritten to reflect that. Our comment on MOD-017R2 regarding the need for a clear statement of conditions when action is required instead of giving an example of when action is required is also applicable here.</p>
National Grid	No	<ul style="list-style-type: none"> o Requirement R1.2 should not be in this standard based on the title of the standard. The standard deals with interruptible demand and DCLM data and requirement R1.2 is more about load forecasting. National Grid suggests deleting R1.2. R1.2 can find place in MOD_17 standard. o With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL. o General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. o General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o General comment - Each entity's expertise should be relied upon to gather the appropriate weather information.
Southern Company Transmission	No	<p>Paragraph 1276 - Adding sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list.</p> <p>Paragraph 1277 - The proposed requirement R2, which includes review of Load forecast accuracy, goes beyond the FERC directive, which includes review of only controllable Load forecast accuracy. Even with that clarification, believe that industry will still consider this controversial.</p> <p>We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability.</p>

Organization	Yes or No	Question 24 Comment
SERC OC Standards Review Group	No	Paragraphs 1276 - 1277 - We suggest that R1.2 and R2 are not in scope for this standard. Also, last year NERC decided to stop using sub-requirements. (Jason will supply the details). While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Dominion	No	<p>Paragraphs 1276 - 1277 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. 1. R1.5 - The language needs to be more specific as to which 'version' of the load forecast is to be compared to actual. Most entities forecast load for any given day at multiple intervals. As example DVP forecasts load for the future 7 days when weather forecast is updated (typically 0400, 1100, and 1600). Weather forecasts are also updated whenever the vendor determines a significant change from previous forecast occurs. This also triggers our load forecast software to produce an updated load forecast. During the actual day, the current day load forecast is updated each hour (for the remaining hours of the day) based upon preliminary 'actual load' for the preceding hour as well as any changes to the weather forecast for the current day.2.</p> <p>R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.</p>
ERCOT ISO	No	Q24 - The proposed language appears to address the directive, but ERCOT ISO disagrees with the added parenthetical language. Furthermore, ERCOT ISO disagrees with the phrase 'if necessary' because it introduces ambiguity.
Indiana Municipal Power Agency	No	Question 23 and 24 - This may be a bigger task than first thought by the SDT. In order to come up with R2 is to have an hour with DCLM and compare it against an hour without DCLM. Then one needs to do some extrapolation to the value of what would be available at peak load. IMPA believes there needs to be more involvement of the industry in this process and time to refine the method. In addition, there is no measure for requirement 2.
American Electric Power	No	<p>R1.2. The standard title is "Forecasts of Interruptible Demands and DCLM Data" yet R1.2 reference peak forecast variation. Clarification is needed on what is peak (LSE, interruptible loads, etc).</p> <p>Secondly, "biasing of each forecast" is not appropriate phrasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias.</p>
Springfield Utility Board	No	SUB respectfully disagree with the assessment that regulatory requirements are not burdensome. As a smaller utility looking to implement demand response via a pilot program of controlled demand, regulatory requirements are becoming overwhelming when considering the benefit of the program with the regulatory cost. Regulatory requirements are a barrier to entry for smaller entities. As a result, Demand Response may not be achieved as rapidly

Organization	Yes or No	Question 24 Comment
		<p>as possible. There needs to be some ability implement small scale demand response programs without tripping all over requirements with excessive penalties.</p> <p>SUB is strongly considering not pursuing DR because of the risk associated with penalties from violations. A potential \$4000 per month benefit is overwhelmed by the potential for a penalty that is ten times or a hundred times or a thousand times the value of the benefit. When looking at the severity level associated with violations it is unjustifiable that a 200kW pilot project for demand response (as an example) that was not somehow captured correctly through a modified standard would trigger a high severity level. The severity level needs to better match the magnitude of the event. Direct Control Load Management in the NERC glossary is DSM that is controlled by the "system operator" (no caps). Yet the standard appears to require that forecasts reflect forecasts of "interruptible demands and Direct Control Load Management". The specific term DCLM which could be argued is important for grid reliability is being confused with "interruptible demands" which may not be controlled by the system operator and may not be known by the utility. The definition of DCLM uses the term "system operator" (no caps). The definition should be modified so that it uses the term "System Operator" interruptible demands might include remote shut off of residential water heaters through a one way communication system which sends a signal for devices to shut off but the communication scheme may not know if the devices actually shut off or even if they were on to begin with. This is not something a system operator can rely upon for grid stability and it is impossible to evaluate variations in forecast.</p> <p>The standard is overly broad, the severity levels extreme, and SUB suggests modifying the severity level to better reflect the impact on the grid. "interruptible demands" should be capitalized. SUB suggests:</p> <ol style="list-style-type: none"> 1) Eliminating interruptible demands from the requirement and just focus on DLCM. 2) Create a new standard for Interruptible Demands with lower severity levels and requirements to remove barriers for entry.
United Illuminating Company	No	<p>United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix. UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated</p>
Midwest ISO Standards Collaborators	No	<p>We do not believe that the directives in paragraph 1276 and 1277 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. We believe the Commission likely would have the same view given their use of "innovative solutions" in their directive in paragraph 1276. Innovation takes time. Clearly, a group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce</p>

Organization	Yes or No	Question 24 Comment
		<p>reliability. Adding sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
Entergy Services	No	<p>While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.</p>
PacifiCorp	Yes	<p>R2 Requires accuracy of forecast vs. actual of within 10%--what level of granularity...BA, etc?Rephrase the language as follows:For Loads that vary based on temperature and/or humidity, temperature and humidity data for the prior year used to normalize demands.</p>
Pepco Holdings, Inc. - Affiliates	Yes	<p>the directive has been met by the changes, the world has advanced since Order 693, and this is not needed.</p>

25. Do you believe the changes made in response to the directive(s) contained in Paragraph 1287 of Order No. 693 are both valid and address the directive(s)?

1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-020-1	Modified Section B Requirement R1. Added Section B Requirement R2. Added VSLs for R2.
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Organization	Yes or No
E.ON U.S.	No
National Grid	No
Xcel Energy	No
Northeast Power Coordinating Council	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
Oklahoma Municipal Power Authority	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No

Organization	Yes or No
Southern Company Transmission	No
Santee Cooper	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
Pepco Holdings, Inc. - Affiliates	No
American Electric Power	No
Springfield Utility Board	No
Midwest ISO Standards Collaborators	No
IESO	No
Arizona Public Service Company	Yes
CECD	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
SDG&E	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Illinois Municipal Electric Agency	Yes

Organization	Yes or No
Consumers Energy Company	Yes
Georgia System Operations Corporation	Yes

Comments on the MOD-020 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1287 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 25 Comment
Ameren	(a) R1 and R2.1 - Add ",DSM," after interruptible demands
IRC Standards Review Committee	Taken in isolation the proposed change to R1 is appropriate. All the identified entities must respond to data requests of reliability entities that require the data. In the context of the entire requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related. FERC is correct that this is a complex issue and the idea that simply mandating forecast data ignores the fact of that complexity. The requirement lacks clarity in definition of what DCLM is; what biases the standard is seeking and who needs what information for reliability. The ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. This change should take into account the findings of those initiatives. The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
Northeast Power Coordinating Council	<ol style="list-style-type: none"> 1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R2.1 - How is this different from MOD-019 R1.1? This seems like a duplication of what is in MOD-019 and perhaps, they should be combined.
Kansas City Power & Light	Directive 1287: Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R2 and R2.1. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by

Organization	Question 25 Comment
	<p>load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit. It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-020. See definition below: Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.</p>
Florida Municipal Power Agency	<p>In Paragraph 1287, this directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.</p>
Oklahoma Municipal Power Authority	<p>It is not clear on how the requirements in R2 are to be accomplished.</p>
Dominion	<p>Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load. It should also be noted that if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.</p>
Entergy Services	<p>Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.</p>
SERC OC Standards Review Group	<p>Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.</p>

Organization	Question 25 Comment
Southern Company Transmission	Paragraph 1287 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
Santee Cooper	Paragraph 1287 - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
ERCOT ISO	Q25 - The language does seem to address the directive, but is likely to be controversial as it goes directly to telling how to do something rather than what needs to be done to ensure reliability. This standard needs to be fully vetted with the industry through the standards development process.
Indiana Municipal Power Agency	<p>Question 25 - This may be a bigger task than first thought by the SDT. In order to come up with R2 is to have an hour with DCLM and interruptible demand, and compare it against an hour without DCLM and interruptible demand. Then one needs to do some extrapolation to the value of what would be available at peak load. IMPA believes there needs to be more involvement of the industry in this process and time to refine the method. In addition, there is no measure for requirement</p> <p>2. IMPA does not see the need (or the directive order requirement) in requirement 2 to send this information to the ERO and Regional Entity. The information in requirement 2 should be sent to the requesting Transmission Operator, Balancing Authority, or Reliability Coordinator when they make the request in requirement</p> <p>1. The ERO and Regional Entity can get the information from the Transmission Operator, Balancing Authority, or Reliability Coordinator which is the way some regions are currently gathering this information.</p>
Pepco Holdings, Inc. - Affiliates	R1 has been appropriately changed; R2 does not need to include the ERO
American Electric Power	R2.1 "...biasing of each forecast" is not appropriate phrasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecasts are not developed with bias.
Springfield Utility Board	SUB respectfully disagrees with the assessment that regulatory requirements are not burdensome. As a smaller utility looking to implement demand response via a pilot program of controlled demand, regulatory requirements are becoming overwhelming when considering the benefit of the program with the regulatory cost. Regulatory requirements are a barrier to entry for smaller entities. As a result, Demand Response may not be achieved as rapidly as possible. There needs to be some ability to implement small scale demand response programs without tripping all over requirements with excessive penalties. SUB is strongly considering not pursuing DR because of the risk associated with penalties from violations. A potential \$4000 per month benefit is overwhelmed by the potential for a penalty that is ten times or a hundred times or a thousand times the value of the benefit.

Organization	Question 25 Comment
	<p>When looking at the serverity level associated with violations it is unjustifiable that a 200kW pilot project for demand response (as an example) that was not somehow captured correctly through a modified standard would trigger a high severity level. The severity level needs to better match the magnitude of the event. Direct Control Load Management in the NERC glossary is DSM that is controlled by the "system operator" (no caps). Yet the standard appears to require that forecasts reflect forecasts of "interruptible demands and Direct Control Load Management". The specific term DCLM which could be argued is important for grid reliability is being confused with "interruptible demands" which may not be controlled by the system operator and may not be known by the utility. The definition of DCLM uses the term "system operator" (no caps). The definition should be modifies to that it uses the term "System Operator" interruptible demands might include remote shut off of residential water heaters through a one way communication system which sends a signal for devices to shut off but the communication scheme may not know if the devices actually shut off or even if they were on to begin with. This is not something a system operator can rely upon for grid stability and it is impossible to evaluate variations in forecast. The standard is overly broad, the severity levels extreme, and SUB suggests modifying the severity level to better reflect the impact on the grid. "interruptible demands" should be capitalized. SUB suggests: 1) Eliminating interruptible demands from the requirement and just focus on DCLM. 2) Create a new standard for Interuptible Demands with lower severity levels and requirements to remove barriers for entry.</p>
<p>Midwest ISO Standards Collaborators</p>	<p>We do not believe that the directives in paragraph 1287 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. A group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability.</p> <p>Adding sub-requirement R2.1 and modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission's ruling in Order 722.</p> <p>Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p>
<p>IESO</p>	<p>We do not understand the meaning of "biasing". Is it operator adjustments? If so, isn't forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires "value-added" actions by the forecaster. Biasing is not a defined term.</p>
<p>Illinois Municipal Electric Agency</p>	<p>Many Reliability Standards Requirements could be eliminated by simply requiring a registered entity to comply with requests from its interconnected functional authorities as part of its registration obligations.</p>

Organization	Question 25 Comment
Consumers Energy Company	Please provide your opinion regarding the Paragraph 1287 VRF and VSLs: In Favor
Georgia System Operations Corporation	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.

26. Do you believe the changes made in response to the directive(s) contained in Paragraph 1300 of Order No. 693 are both valid and address the directive(s)?

1300	The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.	MOD-021-1	Modified Section A 1 and 3.
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Organization	Yes or No
Northeast Power Coordinating Council	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
E.ON U.S.	Yes
Entergy Services	Yes
ERCOT ISO	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes

Organization	Yes or No
IRC Standards Review Committee	Yes
Kansas City Power & Light	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SDG&E	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes
Georgia System Operations Corporation	Yes
Midwest ISO Standards Collaborators	Yes

Comments on the MOD-021 Standard Changes

Summary Consideration:

The majority of commenters agree with the proposed modifications to address this directive. The Response Team thanks the commenters for their support.

Organization	Question 26 Comment
Northeast Power Coordinating Council	<p>1. General comment - If the Transmission Planner gets its information from the LSE, must it duplicate the documentation? The impact of many DSM programs is not measurable.</p> <p>Response: The Response Team does not understand the comment/question. We suggest the commenter to seek informal guidance or request for an interpretation if this relates to the clarity of the existing standard.</p>
Georgia System Operations Corporation	None.
Midwest ISO Standards Collaborators	<p>We agree this represents low hanging fruit that could be modified through this expedited SAR. We do note though that the Compliance section of the standard has been modified which exceeds the scope of the SAR.</p> <p>Response: Thank you for the support. The compliance elements, which are not considered part of the standard, have been updated to reflect the current practices in use today. They do not conflict with the requirements, do not impose any new requirements, and should provide more clarity to entities wishing to comply with the standard. As such, the Response Team believes the updates are both appropriate and within scope.</p>

27. Do you believe the changes made in response to the directive(s) contained in Paragraph 1469 of Order No. 693 are both valid and address the directive(s)?

1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	PRC-004-2	Modified Section B Requirements R1, R2, and R3.
1469	We direct the ERO to consider ISO-NE’s suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.	PRC-004-2	Modified Section B Requirements R1 and R3. Modified Measures M1 and M3. Modified Data Retention.

Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Northeast Power Coordinating Council	No
Consumers Energy Company	No
Kansas City Power & Light	No
Georgia System Operations Corporation	No
American Electric Power	No
Central Lincoln	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No

Pepco Holdings, Inc. - Affiliates	No
PacifiCorp	No
ERCOT ISO	No
E.ON U.S.	No
United Illuminating Company	No
IESO	No
Southern Company Transmission	No
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
Dynegy Inc.	Yes
National Grid	Yes
Oklahoma Municipal Power Authority	Yes
Santee Cooper	Yes
Springfield Utility Board	Yes
US Bureau of Reclamation	Yes
Xcel Energy	Yes
Illinois Municipal Electric Agency	Yes

Indiana Municipal Power Agency	Yes
Florida Municipal Power Agency	Yes
Western Electricity Coordinating Council	Yes

Comments on the PRC-004 Standard Changes

Summary Consideration:

Many commenters disagree with the inclusion of Load-Serving Entity and Transmission Operator in the Applicability Section and in Requirements R1 and R3 since these entities are not owners of BES facilities. Upon reviewing these comments and the Functional Model, the Response Team agrees with the commenters' view. The proposed modifications to address the ISO-NE's suggestion, namely, to include LSE and TOP in the PRC-004 standard, have been removed from consideration for balloting. With this decision, comments addressing these particular changes will be not be responded to individually at this time. However, they will be retained for future consideration.

Some commenters indicate that the change from RRO to RE in the Requirements needs to be reflected in the Measures. The Response Team agrees and has changed Measures M1, M2 and M3 by replacing "Regional Reliability Organization procedures developed for PRC-003 R1" with "Regional Entity's procedures."

Some commenters disagree with replacing Regional Reliability Organization with Regional Entity as directed by the Commission in Order 693, Paragraph 1469. Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." We do not find using the term Reliability Entity inappropriate. The proposed change to Requirement R2 and the Compliance Section are retained and will be included in the recirculation ballot.

Organization	Question 27 Comment
IRC Standards Review Committee	<p>Taken in isolation the proposed changes to R1, R2 and R3 are appropriate. In the context of the entire requirement, the proposed change raises the following issues:</p> <ul style="list-style-type: none"> o The LSE should not be included in requirements R1 and R3 because they are not required to have any assets that would be used for mitigation of generator protection systems misoperations. LSEs arrange energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or distribution facilities and their associated protection systems. Further, since both LSEs and TOPs do not own physical assets, they should not be included in the applicability section. ISO-NE, who originally submitted the comment which resulted in the Directive, agrees and believes that the directive is no longer applicable. o The changes to R1 are problematic because they introduce a joint applicability (i.e. joint ownership of a Protection System). FERC has required clear applicability - and joint applicability raises the question of how to split responsibility and compliance regarding the mandate to analyze a misoperation, and to develop a mitigation plan. <p>Response: Please see the response in Summary of Consideration.</p>
NERC Standards Review	#27. FERC Order 693 does not state that "individually or jointly" entities that own a Protection System shall analyze and develop a

Organization	Question 27 Comment
Subcommittee	<p>Correction Action Plan. This statement does not improve this Standard. Anyone of the applicable entities can be joint owners of a transmission Protection System but one entity will have this requirement to fulfill those actions of this requirement. Recommend deleting “individually or jointly”.</p> <p>Response: The proposed change goes beyond the scope of this project. However, with the decision to not proceed with changes to R1 and R3 to address the directive, your suggestion will be retained for future consideration when the standard is revised.</p>
Ameren	<p>(a) The Glossary of Terms still uses RRO, why the change to Regional Entity?</p> <p>(b) The industry has finally approved Project 2009-17 which clarifies the transmission Protection System border. But 2009-17 refers to PRC-004-1. Please expand 2009-17 so that it is applicable to this proposed PRC-004-2, or better yet incorporate the 2009-17 wording into PRC-004-2.</p> <p>(c) We do not believe that LSE and TOP would own Protection Systems. The standard should not apply to LSE and TOP.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Northeast Power Coordinating Council	<p>1. Since LSEs and TOPs do not own physical assets, they should not be included. ISO - NE agrees and believes that the directive is no longer applicable.</p> <p>2. There is still no clarification on when a DP "owns" a transmission Protection System. Distribution Providers likely own and/or operate equipment matching the definition in the NERC Glossary; however, such does not constitute the owning and/or operation of a “transmission” protection system. In what instances would the NERC Glossary definition of a Protection System apply to a DP?3.</p> <p>R3 should be reworded to reflect RE just like the other requirements have been modified.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Consumers Energy Company	<p>Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM.</p> <p>We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM.</p> <p>Response: Please see the response in Summary of Consideration.</p>

Organization	Question 27 Comment
Kansas City Power & Light	<p>Directive 1469:It is inappropriate to include Regional Entities as an entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. The requirements should continue to point to the Regional Reliability Organization or the Reliability Coordinator as the entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to establish the criteria and procedures for analysis and reporting of relay mis-operations as defined in this Standard PRC-004. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.In addition, it is sufficient to include as an applicable entity the Transmission Owner. It is not necessary, nor is the directive concerned with, the inclusion of the Transmission Operator. The NERC Functional Model clearly indicates the relaying system is the responsibility of the Transmission Owner and not the Transmission Operator. Recommend removal of the Transmission Operator from the Applicability Section and the subsequent references in the requirements.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Georgia System Operations Corporation	<p>Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed.R3 refers to Regional Reliability Organization and Regional Entity in the same sentence. The same inconsistency exists in the Measures.</p> <p>Response: Please see the response in Summary of Consideration.</p>
American Electric Power	<p>If these changes are made, this will create applicability to entities that are not involved in other related PRC standards. AEP does not support this "urgent" action as it will create confusion between this and other PRC standards going forward. Furthermore, in AEP's experiences, TOP and LSEs are likely not to have involvement in these requirements, but it should be the TO, DP and GO that are involved.The inclusion of the LSE in this standard continues to muddy the water between the role of the LSE and the DP. The NERC Statement of Registry Criteria states that a DP "Provides and operates the 'wires' between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage." In addition, an LSE is defined as an entity that "secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers."This issue has been a considerable problem with how standards were written in the past and NERC has committed to addressing these unfortunate and confusing overlaps in responsibility, but these proposed changes will only perpetuate the problem. We recommend that any entity</p>

Organization	Question 27 Comment
	<p>that has such protection systems should be registered as a TO, DP or GO, The issue then would become one of the ability of the RE to appropriately register entities, not a deficiency in the NERC standards. Again, the other PRC standards are focused on the TO function. This would again cause a mismatch in the applicability with these standards.</p> <p style="padding-left: 40px;">The first sentence of requirement R1 should be revised to begin "The Transmission Owner, Distribution Provider and the Generator Owner that individually or jointly owns a transmission Protection System, shall each..."</p> <p>AEP Generation owns transmission Protection Systems and believes that the intent of this standard is that all transmission Protection System misoperations are analyzed, regardless of the ownership of the equipment. Furthermore, revising requirement R1 brings the analysis requirements in line with the documentation requirements of R3 which requires a Generator Owner who owns a transmission Protection System to "... provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans..."</p> <p>Also, note that "Regional Reliability Organization" should actually be "Regional Entity".</p> <p>Measure M1 should be revised to include the Generator Owner, as suggested above, and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."</p> <p>Measure M2 should be revised to be consistent with R2 and read "The Generator Owner shall have evidence it analyzed its generator Protection System Misoperations..." and to and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."</p> <p>Measure M3 should be revised to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."</p> <p>The Data Retention section should be revised to remove reference to the "generation Protection System" and should instead read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall retain..."The Additional Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..."</p> <p>Response: Please see the response in Summary of Consideration.</p>
Central Lincoln	<p>It remains unclear how an entity can comply with any of the requirements in the absence of a Regional Entity procedure.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Entergy Services	<p>Paragraph 1469 - Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard.</p> <p>We do not believe that R1.2 and R1.3 should be included in this standard.</p>

Organization	Question 27 Comment
	<p>Likewise, we do not believe that R3.2 and R3.3 should be included in this standard.</p> <p>Response: Please see the response in Summary of Consideration.</p>
SERC OC Standards Review Group	<p>Paragraph 1469 - Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and, therefore; should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and, therefore; should be removed.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Midwest ISO Standards Collaborators	<p>Paragraph 1469 clearly states the Commission’s expectation that this directive will be addressed through the five-year cycle. Why does this need to be expedited? However, we agree that the changes meet the directive regarding modifying regional reliability organization to Regional Entity. The Commission’s directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model.</p> <p>Adding sub-requirements R1.1 through R1.3 and R3.1 through R3.3 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p> <p>Response: Please see the response in Summary of Consideration.</p>
Pepco Holdings, Inc. - Affiliates	<p>Pepco Holdings Affiliates believe the SDT has erred in stating that a protection system may be jointly owned. This was not an issue in Order 693. By definition, A TOP would not own a protection system.</p> <p>Order 693 did not require the addition of LSEs or TOPs, only that they be considered. An LSE that “owns” a protection system is also a DP, so LSE applicability is not needed.</p> <p>Response: Please see the response in Summary of Consideration.</p>

Organization	Question 27 Comment
PacifiCorp	<p>PRC-004-2 should be applicable to either the Transmission Owner/Generator Owner or the Transmission Operator/Generator Operator, but not both. If PRC-004-2 is applicable to both Transmission Owner/Generator Owner and Transmission Operator/Generator Operator, the standard should more clearly define how the standard applies to each of these entities. In many instances, a Protection System may be owned by one entity but operated by another. Furthermore, in many instances, both the owner and operator of the Protection System are registered as Transmission Owner and Transmission Operator. Given this factual scenario and the currently proposed PRC-004-2, both entities could individually be responsible for compliance related to the same Protection System. As currently written, it is unclear whether this is the intent of the standard. In order to provide responsible entities with clear guidance on their regulatory responsibilities, PacifiCorp suggests that the standard clearly identify only one entity that is responsible for compliance. Short of this, PacifiCorp suggests that the standard more clearly state how it applies to each of the responsible entities listed.</p> <p>Response: Please see the response in Summary of Consideration.</p>
ERCOT ISO	<p>Q27 - The changes made appear to assume that Regional Entities, Load Serving Entities, and Transmission Operators are operating entities when in fact REs and LSEs are not operating entities. There is not a direct one to one correlation between RRO and RE. The SDTs have been directed by NERC, as they work on the standards revision projects, to assign RRO responsibilities to the appropriate functional entities. ERCOT ISO agrees that TOPs should be added to the applicability section.</p> <p>Response: Please see the response in Summary of Consideration.</p>
E.ON U.S.	<p>The FERC's directive is to change references from RRO to RE. R3, M1,M2 and M3 still reference RRO.</p> <p>Response: Thank you for catching the discrepancy. Measures M1, M2 and M3 have been revised accordingly to replace "Regional Reliability Organization procedures developed for PRC-003 R1" with "Regional Entity's procedures."</p>
United Illuminating Company	<p>United Illuminating believes the transmission owner should be listed in the sub bullet 1.1.</p> <p>R1 should start "Any entity listed below that individually or jointly...".</p> <p>Same comment for R3.</p> <p>United Illuminating points out to the Drafting Team that Paragraph 1469 also refers this change to PRC-005, 8, 11, 15, 16, 17, 21.</p> <p>Response: Please see the response in Summary of Consideration. Your specific suggestions will be considered in future revision to this standard.</p>
IESO	<p>We agree with the proposed changes to the Applicability Section, Requirements R1, R2 and R3 except the inclusion of the Load-Serving Entity. LSEs arrange secure energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or</p>

Organization	Question 27 Comment
	<p>distribution facilities and their associated protection systems. We suggest to remove LSE from the Applicability Section and the three requirements.</p> <p>Further, there are two typos in R3: the “o” in “Generation owner” should be capitalized; and “Regional Reliability Organization” should be “Regional Entity”.</p> <p>Response: Please see the response in Summary of Consideration</p>
Southern Company Transmission	<p>With respect to the FERC Order 693 directive in Paragraph 1469, the reference to the Regional Reliability Organization in R3 should be replaced with the Regional Entity. (replace “... shall each provide to its Regional Reliability Organization...” with “...shall each provide to its Regional Entity...”)</p> <p>M1, M2, and M3 need to be changed to match R1, R2, and R3 by: (replacing “... according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.” with “... according to the Regional Entity’s procedures.”)</p> <p>Requirement 1 refers to transmission protection systems in the case of TO’s, DP’s, TOP’S and LSE’s while Requirement 2 specifically mentions generator protection systems in reference to GO’s.</p> <p>In Requirement 3 however it is unclear whether Generator Owners are held responsible for generator protection systems, transmission protection systems or both.</p> <p>Compliance Section - Data Retention - Is the intent that GO’s should retain data for an evaluation not prescribed in the Requirements - in the case of a Generator Owner evaluating transmission protection systems?</p> <p>Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard.</p> <p>We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed.</p> <p>Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed. The Commission’s directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model.</p> <p>Response: Please see our response in Summary Consideration. In addition, thank you for catching the discrepancy. Measures M1, M2 and M3 have been revised accordingly to replace “Regional Reliability Organization procedures developed for PRC-003 R1” with “Regional Entity’s procedures.”</p>

Organization	Question 27 Comment
Illinois Municipal Electric Agency	<p>Can live with, but addition of LSE does not make sense given current Reliability Functional Model definition. Also, revisions are not consistent with our understanding of NERC's intent to get away from the sub-requirement structure.</p> <p>Response: Please see our response in Summary Consideration.</p>
Indiana Municipal Power Agency	<p>IMPA supports this change, but transmission protection system needs to be defined by a SDT in the near future.</p> <p>Response: The definition of protection system is being addressed under a separate project.</p>
Florida Municipal Power Agency	<p>The directive is to "consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section". In this case, while we do not oppose the change, we do not know of any cases where an LSE or TOP has a transmission Protection System, so, we do not know why LSEs and TOPs are being added to the applicability. Can someone identify a transmission Protection System owned by an LSE or TOP that is not already covered by a TO, GO or DP?</p> <p>Response: Please see our response in Summary Consideration.</p>
Western Electricity Coordinating Council	<p>While the proposed changes are to PRC-004, PRC-003-0 is a Fill-in-the-blank standard and is referenced by PRC-004. As NERC revises the Fill-in-the-blank standards to remove the Regional Reliability Organization as an applicable entity, the language of PRC-004-2 (as well as many others) will need to be revised to remove the phrase "according to the Regional Entity's procedures."</p> <p>Response: The Response Team agrees with your view. However, until PRC-003 is revised, PRC-004 still needs to make reference to an approved standard. Your comments will be considered in future revisions to the inter-related standards.</p>

28. Do you believe the changes made in response to the directive(s) contained in Paragraph 1858 of Order No. 693 are both valid and address the directive(s)?

1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	VAR-001-2	Added Section A 4.3. Modified Section B Requirement R5.
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Organization	Yes or No
Ameren	No
American Electric Power	No
CECD	No
Consumers Energy Company	No
Entergy Services	No
ERCOT ISO	No
IESO	No
Kansas City Power & Light	No
National Grid	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SERC OC Standards Review Group	No
Springfield Utility Board	No
Arizona Public Service Company	Yes

Organization	Yes or No
Dominion	Yes
Dynergy Inc.	Yes
E.ON U.S.	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
Midwest ISO Standards Collaborators	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Southern Company Transmission	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

29. Do you believe the changes made in response to the directive(s) contained in Paragraph 1879 of Order No. 693 are both valid and address the directive(s)?

1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	VAR-001-2	Modified Section B Requirements R2, R5, R8, and R9.
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Organization	Yes or No
National Grid	No
Xcel Energy	No
Springfield Utility Board	No
Ameren	No
United Illuminating Company	No
Georgia System Operations Corporation	No
CECD	No
Consumers Energy Company	No
IESO	No
E.ON U.S.	No
Northeast Power Coordinating Council	No
Southern Company Transmission	No
Santee Cooper	No

Organization	Yes or No
Entergy Services	No
SERC OC Standards Review Group	No
ERCOT ISO	No
Midwest ISO Standards Collaborators	No
Arizona Public Service Company	Yes
Dynergy Inc.	Yes
Florida Municipal Power Agency	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Municipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes
American Electric Power	Yes
Kansas City Power & Light	Yes

Organization	Yes or No
Dominion	Yes

Comments on the VAR-001 Standard Changes

Summary Consideration:

Many commenters disagree with including “load shedding” in the proposed changes to Requirements R2, R5 and R9. The Response Team agrees with their comments, and has removed this term from Requirements R2, R5 and R9.

Some commenters suggest removing R5 altogether. The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission and the ERO must address these directives. The proposal to strike R5 or to change the language to reflect the tariff requirements for arranging reactive support will be considered in future revision to this standard.

Some commenters disagree with the insertion of the list of reactive resources. The insertion is meant to provide examples of control measures that are resource and business arrangement neutral and can be arranged or deployed to provide the needed reactive capability.

Some commenters suggest replacing the TSP with the TOP in R5. This suggestion will be retained for consideration in future revisions as this change is outside of the scope of this Project.

Some commenters disagree with the use of the term “controllable load”. The intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of an alternate term such as Direct Control Load Management (DCLM) raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, this suggestion will be retained for consideration in future revisions.

Organization	Question 29 Comment
IRC Standards Review Committee	<p>Paragraph 1819The mark-up to R9, as written, implies that load shedding can be used for first Contingency conditions since first contingency includes single contingencies. We disagree with this change, and suggest that load shedding be removed from the requirement. In fact, the list of actions need not be included in the requirement since the inclusion of a list of reactive services is not appropriate without proper vetting.</p> <p>Paragraph 1858Taken in isolation the proposed changes to R5 are appropriate.The issue is with the requirement itself. R5 inappropriately identifies the TSP as the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement.</p> <p>Response: The Response Team agrees with the concern over “load shedding”, and has removed this term from Requirements R2, R5 and R9.</p> <p>With respect to the comment on including the list of actions, these are included as possible actions since the requirement clearly indicates “may include, but not limited to”. This provides the flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions.</p> <p>With respect to the TOP versus TSP comment, we will retain this comment for consideration in future revisions, as this change is</p>

Organization	Question 29 Comment
	<p>outside of the scope of this Project.</p>
<p>central Maine Power Company</p>	<p>R10 which is not addressed by this but should be. A violation does not occur until after the 30 minutes has expired. Until then the requirement is being exceeded. TOP-007 has similar wording which is confusing and incorrect.</p> <p>Response: We will retain this comment for consideration in future revisions, as this change is outside of the scope of this Project.</p>
<p>Springfield Utility Board</p>	<p>"controllable load" is not a defined term and is too broad. "load shedding" is not a defined term and is too broad. The NERC glossary of terms uses "Direct Control Load Management" (which needs to be modified so that "system operator" is in caps "System Operator"). SUB appreciates the intent, but the proposed changes make the situation worse, do not improve reliability, increase confusion and lack of clarity, pull in DSM programs which have no bearing on voltage or reactive control, and diminish reliability. The language referring to controllable load and load shedding should be eliminated and replaced with "Direct Control Load Management". language change: "which may include, but is not limited to, reactive generationscheduling; transmission line and reactive resource switching, and, if necessary, Direct Control Load Management"</p> <p>Response: The Response Team has removed the term "load shedding" from Requirements R2, R5 and R9.</p> <p>With respect to the use of the term "controllable load", the intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of DCLM raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, we will retain this comment for consideration in future revisions.</p>
<p>Ameren</p>	<p>(a) R2 - load shed is not a resource but a stop gap (b) R5 - Add "for all load levels it expects to have on the TSP system" removing "controlled load, and if necessary, load shedding". (c) R5 - How does PSE arrange for load shedding?</p> <p>Response: The Response Team has removed the term "load shedding" from Requirements R2, R5 and R9.</p> <p>With respect to the use of the term "controllable load", the intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of DCLM raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, we will retain this comment for consideration in future revisions.</p>
<p>United Illuminating Company</p>	<p>United Illuminating disagrees with including load shed in R2. R2 is in a planning horizon versus R8 and R9 which is in real-time operating horizon. United Illuminating does not believe it is appropriate PLAN on load shed to meet a reactive requirement. Load shed (R8 and R9) is appropriate in the real time environment to protect the BES.</p> <p>Response: The Response Team has removed the term "load shedding" from Requirements R2, R5 and R9.</p>
<p>Georgia System Operations</p>	<p>29) We disagree with the inclusion of load shedding as a resource in VAR-001 R2, R5, and R9. Controllable load is certainly a</p>

Organization	Question 29 Comment
Corporation	<p>resource and that is what FERC directed to be included. Load shedding is certainly an appropriate action to be included in requirement R8, but considering load shedding (as distinct from controllable load) as a resource would only allow an entity to carry less true resources to meet the requirement. Perversely the inclusion of load shedding as a resource would make it difficult to violate the requirement, because an entity would always have sufficient load shedding resources (you can shed your entire load in theory).</p> <p>Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.</p>
CECD	<p>CECD is concerned with the impact to the BA if load shedding is used as a reactive resource and feels that the standard must be modified to require the TOP notify the BA if load shedding is applied in this manner.</p> <p>Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.</p>
Consumers Energy Company	<p>Changes for directives in Paragraph 1858: Disapprove Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Changes for directives in Paragraph 1879: Disapprove Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM.</p> <p>Response: LSE is included in R5 only, which we assess is appropriate since it is defined as: “The functional entity that secures energy and transmission service (and reliability related services) in the current Functional Model.</p> <p>Regarding your comment on TOP versus TO, R1 and R3 stipulates the requirement in an operating environment. We do not see any wording in these Requirements that suggest “owning” facilities as you indicate. We agree with you that LSEs and TOPs are operating entities, and that is exactly what this standard is meant to address (the operating domain). We do not see any issues with including LSEs and TOPs (and PSEs) in this standard.</p>
IESO	<p>For Para 1858, we agree with the additional wording in Requirement R5 but there is a fundamental issue with the last part of the requirement as written. The TSP should not be the entity responsible for identifying reactive requirements. It should be the TOP</p>

Organization	Question 29 Comment
	<p>that is responsible for identify this requirement.</p> <p>Response: With respect to the TOP versus TSP comment, we will retain this comment for consideration in future revisions as the proposed change is outside of the scope of this Project.</p>
E.ON U.S.	<p>In paragraph 1879, FERC says to “consider the concern...”, not to actually change requirements. Providing optional methods or examples does not add clarity to the standard</p> <p>Response: The Commission did not ask the ERO to consider. Paragraph 1879 clearly states that the Commission “...direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1”. The proposed changes comply with this directive.</p>
Northeast Power Coordinating Council	<p>Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. The mark-up to R9, as written, implies that load shedding can be used for first contingency conditions. This is detrimental to reliability.</p> <p>Response: With respect to the comment on specific technologies, the proposed changes make no mention of any technologies. We suspect this comment is intended for another standard.</p> <p>With respect to “load shedding”, the Response Team has removed this term from Requirements R2, R5 and R9.</p>
Southern Company Transmission	<p>Paragraph 1858 - However, this is a tariff issue and unrelated to reliability.</p> <p>Paragraph 1879 - In R9, shedding load following the first contingency would seem to violate TPL-002, Category B events.</p> <p>Response: The Response Team has removed this term from Requirement R9.</p>
Santee Cooper	<p>Paragraph 1858 - Requirement 5 should be removed completely as we consider this to be tariff related and not reliability related.</p> <p>Paragraph 1879 - Recommend removing the insertions in Requirement 2 and Requirement 9. We recommend removing Requirement 5 completely for reason stated above. Requirement 8 we recommend removing all the wording between the dashes.</p> <p>Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions.</p> <p>With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the “which may include, but not limited to”. This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions.</p>

Organization	Question 29 Comment
Entergy Services	<p>Paragraph 1858 - We suggest striking all of R5. The requirement for the Transmission Customer to purchase ancillary services including voltage support, and the ability to self-supply is a tariff issue and unrelated to reliability.1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking “- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -“. This makes the standard resource neutral, which is apparently the aim of FERC. Including a partial list of resources that qualify as reactive resources, does not improve the reliability of the standard.</p> <p>Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions.</p> <p>With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the “which may include, but not limited to”. This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions. We feel that this flexibility supports the “resource neutral” notion.</p>
SERC OC Standards Review Group	<p>Paragraph 1858 - We suggest striking all of R5. This is a tariff issue and unrelated to reliability.1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking “- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -“. This makes the standard resource neutral, which is apparently the aim of FERC.</p> <p>Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions.</p> <p>With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the “which may include, but not limited to”. This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions. We feel that this flexibility supports the “resource neutral” notion.</p>
ERCOT ISO	<p>This standard needs to be fully vetted with the industry through the standards development process. Reactive resources and reactive services will be controversial due to the varying market structures in which these products are arranged and provided.</p> <p>Response: The proposed changes to R2, R5 and R9 serve to provide examples which are resource and business arrangement neutral.</p>
Midwest ISO Standards Collaborators	<p>We agree that the changes address paragraph 1858 but question the need for the changes or even the need for the existing requirement. This requirement is essentially a reflection of the FERC pro-forma tariff requirement that transmission customers (usually PSEs) must purchase reactive service or arrange for it themselves. Has any PSE ever arranged reactive service themselves? The transmission operator will still have to take the necessary steps to ensure reactive power is sufficient to support voltage.</p> <p>While changes to R2, R5, R8 and R9 may address the Commission directives in paragraph 1879, we do not agree with the</p>

Organization	Question 29 Comment
	<p>changes and believe a better solution is available. Rather than adding a laundry list of methods to control voltage, we suggest the requirements should be silent on the methods. Thus, we suggest that the additions to R2, R5, R8 and R9 be removed and that “reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding” be struck from R8. In this way, Commission’s goal of ensuring the reliability standards do not prevent Commission policy from being implemented is met.</p> <p>The proposed changes appear to be using Reliability Standards to further Commission policy on demand response which is surely not their intent since Reliability Standards are about maintaining a reliable grid. We agree that no changes are necessary to the standard to address SoCal Edison’s concerns in paragraph 1878. NERC simply needs to offer their explanation in the regulatory filing.</p> <p>Response: The proposed changes are meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must comply. The issue with whether or not PSE or LSE needs to comply with a reliability standard that may be viewed as a tariff requirement will be debated in future major revision to this standard.</p> <p>The proposed changes to R2, R5 and R9 serve to provide examples of control measures which are resource and business arrangement neutral that can be deployed to provide the needed reactive capability.</p> <p>The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.</p>
American Electric Power	<p>AEP does not agree with expanding the scope to the LSE in R5. Furthermore, the existing applicability to the PSE is not a reliability related requirement as this service is provided by the TSP by default. We do not agree with adding “which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding -” to R5 for the PSE and LSE functions. These entities do not have many of the capabilities as listed.</p> <p>Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must comply. The issue with whether or not PSE or LSE needs to comply with a reliability standard will be debated in future major revision to this standard.</p> <p>The proposed changes to R2, R5 and R9 serve to provide examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability.</p> <p>We agree that the PSE and LSE may not have many of the capabilities as listed. However, Requirement R5 asks that they “...arrange for (self-provide or purchase) reactive resources...”. We do not think that their limited capability is an impediment to complying with the requirement.</p>
Kansas City Power & Light	<p>Directive 1858: The Purchase-Selling will have provisions for reactive support within the ancillary services available to it. Recommend modifying the language in requirement R5 to reflect the exercise of reactive support as provided within the ancillary services available and remove the prescriptive parts of this requirement related to the various actions that can be taken by a</p>

Organization	Question 29 Comment
	<p>Transmission Operator or Transmission Service Provider.</p> <p>Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission and the ERO must address the directives. The proposal to modifying the language in requirement R5 to reflect the exercise of reactive support as provided within the ancillary services available will be considered in future revision to this standard.</p> <p>The listing provides examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability.</p>
Dominion	<p>Paragraph 1858 - We suggest striking all of R5. These requirements are contained in each Transmission Service Provider's tariff. This issue can impact reliability only when the entity substantially fails to meet its obligation under the respective OATT. 1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC.</p> <p>Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must address. The need to strike the entire R5 in view of the assessment that these requirements are contained in each Transmission Service Provider's tariff will be considered in future revision to this standard.</p> <p>The listing inserted to R2 and R9 provides examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability. This also applies to the listing already existing in R8.</p>

30. The motivation for this project is to demonstrate that NERC is working to address the directives in Order 693. Do you agree with this?

Summary Consideration:

Many commenters indicate that a number of directives ask the ERO to consider making the directed changes at the next standard revision cycle. We are aware of the language but the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was therefore taken to identify and address those directives that appeared to require simple changes.

The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comments.

Some commenters suggest that a project like this could wait until after the new Standards Process Manual (SPM) is approved so that the new SPM can be used to more expeditiously develop the intended standard changes. However, while the new SPM has been adopted by the Board of Trustees, until it is approved by the regulators it cannot be used to support a project like this one. The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards development procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.

Some commenters indicate that Standard EOP-003 that is included in this project creates a conflict with another project for which a revised EOP-003 is also posted for commenting and balloting. We appreciate this comment, and have removed EOP-003 from consideration for balloting in this project.

Organization	Yes or No	Question 30 Comment
Xcel Energy	No	
IESO	No	<p>A number of the directives included in the package clearly indicates that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an on-going project runs the risk of contradicting with the SDT's direction of their proposed revisions or may need to be undone at a later stage. We urge the Standards Committee to ensure that adequate coordination among projects to avoid duplicated effort and more importantly that their directions do not run counter of each other and confuse the industry.</p> <p>Response: We recognize that some of the directives ask for consideration for changes at the next standard revision</p>

Organization	Yes or No	Question 30 Comment
		<p>cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was therefore taken to identify and address those directives that appeared to require simple changes.</p> <p>The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.</p>
IRC Standards Review Committee	No	<p>A number of the directives included in the package clearly indicates that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, can wait or be assigned to the existing SDTs. Implementing changes separately from an on-going project runs the risk of contradicting with the SDT's direction of their proposed revisions or may need to be undone at a later stage. We urge the Standards Committee to ensure that adequate coordination among projects to avoid duplicated effort and more importantly that their directions do not run counter of each other and confuse the industry. NERC and FERC must work together to resolve reliability issues. However, complex issues are not resolved by simple changes; and simple issues do not deserve to be expedited (over NERC and FERC prioritized projects). The idea of expediting non-impactive requirements or of addressing complex issues helps neither the Industry (who must expend resources on this SAR) nor NERC nor FERC.</p> <p>Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was therefore taken to identify and address those directives that appeared to require simple changes.</p> <p>The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.</p>
National Grid	No	<p>A number of the directives included in the package clearly indicate that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an ongoing project runs the risk of contradicting the SDT's direction of their proposed</p>

Organization	Yes or No	Question 30 Comment
		<p>revisions, or may need to be undone at a later stage. The Standards Committee should ensure adequate coordination among projects to avoid duplication of effort, and more importantly that their directions do not run counter to each other resulting in industry confusion. NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by looking at a list of NERC's filings to the Commission, their standards development website, participating in the standards development process, and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved Reliability Standards Development Process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the Reliability Standards Development Process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, the quality of standards may ultimately suffer, and could be detrimental to reliability if we do not take the necessary time to produce quality standards. This SAR attempted to identify "low hanging fruit" directives from Order 693 that could be acted upon quickly. While at face value this seems like a simple idea, actual execution turned out to be challenging as evidenced by lack of coordination between some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications (such as changing the NERC OC to the ERO in BAL-002) is not as straightforward and insignificant as it appears (please see our comments on that standard above). The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will necessarily be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time. We believe, unfortunately, that in this attempt to "demonstrate progress", the industry may again be seen as not being able to make "unsubstantial changes" (which are, in fact, substantial).</p> <p>Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was therefore taken to identify and address those directives that appeared to require simple changes.</p> <p>The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank</p>

Organization	Yes or No	Question 30 Comment
		<p>you for the comment.</p> <p>With respect to the EOP-003 standard, we appreciate the industry comments that point to the simultaneous posting issue. For this reason, changes to EOP-003 has been removed fro consideration for balloting along with the others for this project.</p>
<p>Northeast Power Coordinating Council</p>	<p>No</p>	<p>A number of the directives included in the package clearly indicate that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an ongoing project runs the risk of contradicting the SDT’s direction of their proposed revisions, or may need to be undone at a later stage. The Standards Committee should ensure adequate coordination among projects to avoid duplication of effort, and more importantly that their directions do not run counter to each other resulting in industry confusion. NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by looking at a list of NERC’s filings to the Commission, their standards development website, participating in the standards development process, and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved Reliability Standards Development Process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the Reliability Standards Development Process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, the quality of standards may ultimately suffer, and could be detrimental to reliability if we do not take the necessary time to produce quality standards. This SAR attempted to identify “low hanging fruit” directives from Order 693 that could be acted upon quickly. While at face value this seems like a simple idea, actual execution turned out be challenging as evidenced by lack of coordination between some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications (such as changing the NERC OC to the ERO in BAL-002) is not as straightforward and insignificant as it appears (please see our comments on that standard above). The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will necessarily be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time. We believe, unfortunately, that in this attempt to “demonstrate progress”, the industry may again be seen as not being able to make “unsubstantial changes” (which are, in fact, substantial).</p> <p>Response: We recognize that some of the directives ask for consideration for changes at the next standard revision</p>

Organization	Yes or No	Question 30 Comment
		<p>cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was therefore taken to identify and address those directives that appeared to require simple changes.</p> <p>The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.</p> <p>With respect to the EOP-003 standard, we appreciate the industry comments that point to the simultaneous posting issue. For this reason, changes to EOP-003 has been removed from consideration for balloting along with the others for this project.</p>
Midwest ISO Standards Collaborators	No	<p>NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by quickly looking at a list of NERC's filings to the Commission, their standards development web site, participating in the standards development process and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved reliability standards development process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the reliability standards development process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the gallant efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, we fear that the quality of the standards may ultimately suffer and could be detrimental to reliability if we do not take the necessary time to produce quality standards. This SAR attempted to identify "low hanging fruit" directives from Order 693 that could be quickly acted upon. While at face value, this seems like a simple idea but actual execution turned out to be challenging as evidenced by lack of coordination with some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement with one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications, such as changing the NERC OC to the ERO in BAL-002, are not as straightforward as they appear. (Please see our comments on that standard.) The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time.</p>

Organization	Yes or No	Question 30 Comment
		<p>Response: The new Standards Process Manual (SPM) has been adopted by the Board of Trustees. However, until the SPM is approved by the regulators, it cannot be used to support a project like this one. The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards development procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>
United Illuminating Company	No	<p>The directives in Order 693 should be addressed via the work plan and review of standards. This exercise does not progress the development of clear standards with a performance base and measurable requirements. A work plan should be developed to prioritize and address the development of new and revised Standards.</p> <p>Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>The NERC SC will soon launch other projects that will provide more adherence to the results-based concept to improve the quality of future standards. The standard development work plan is constantly under review, and adjusted as appropriate, to ensure proper coordination and adequate resource allocation.</p> <p>Thank you for the comment.</p>
US Bureau of Reclamation	No	<p>The process to modify these standards is not following the accepted and approved process. The excuse that "FERC has expressed concern that industry and NERC have been less responsive than desired in providing a timely resolution to those directives." offers no urgent or compelling reason for this extraordinary step. It is suggested that NERC utilize the conventional standard modification process for the changes requested by FERC.</p> <p>Response: Thank you for the comment. We will forward this to the Standards Committee for consideration.</p>
Ameren	No	<p>There is a considerable benefit to follow the normal process of vetting and thoroughly considering all perspectives/aspects. This is evident from number of comments made on this project.</p> <p>Response: The NERC SC, in support of the initiative to illustrate industry responsiveness to directives, took the action to deviate from the existing standards development procedure. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>

Organization	Yes or No	Question 30 Comment
American Electric Power	No	<p>This is a redundant project, and effort should rather be spent in completing the existing project.</p> <p>Response: The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards development procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>
Southern Company Transmission	No	<p>We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. We fear that the quality of the standards may ultimately suffer and could be detrimental to reliability if we do not take the necessary time to produce quality standards.</p> <p>Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>
Arizona Public Service Company	Yes	
Central Lincoln	Yes	
Consumers Energy Company	Yes	
Dominion	Yes	
Dynergy Inc.	Yes	
Entergy Services	Yes	
Illinois Municipal Electric Agency	Yes	

Organization	Yes or No	Question 30 Comment
Indiana Municipal Power Agency	Yes	
Kansas City Power & Light	Yes	
PacifiCorp	Yes	
Santee Cooper	Yes	
SDG&E	Yes	
SERC OC Standards Review Group	Yes	
Oklahoma Municipal Power Authority	Yes	<p>Agree that is the intent of the project. However, in some cases, there is still too much ambiguity to approve the standard as currently drafted.</p> <p>Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>
CECD	Yes	<p>CECD wants to emphasize that (1) the expedited process should be used very selectively in situations where it is truly warranted, not simply to meet deadlines and (2) that a reasonable review and comment period is essential to maintaining the integrity of the standards development process.</p> <p>Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p> <p>Thank you for the comment.</p>
Georgia System Operations Corporation	Yes	None.
Pepco Holdings, Inc. - Affiliates	Yes	Pepco Holdings Affiliates support this effort to show awareness of the Order 693 directives, though we share the

Organization	Yes or No	Question 30 Comment
		<p>concerns of many that several standards needing full review have been only slightly modified to meet the directives.</p> <p>Response: Thank you for the support. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p>
Springfield Utility Board	Yes	<p>SUB agrees with the intent and is strongly supportive of this process.</p> <p>Response: Thank you for the support.</p>
NERC Standards Review Subcommittee	Yes	<p>The Midwest Reliability Organization’s NERC Standards Review Subcommittee (NSRS) understands the position that the ERO is presently in when faced with the task of incorporating the Commissions directives as written in FERC Order 693. The NSRS agrees that there are “specific” directives that the Commission has presented to the industry and the ERO for inclusion into presently mandatory reliability Standards. The monumental task of providing Reliability Standards that incorporate a word for word placement would only provide an unjust burden on the adequate level of reliability of the Bulk Electric System. Upon the review of FERC Order 693, the NSRS wishes to point out to the ERO that the Commission has stated in paragraph 186 of FERC Order 693 that; 186. Thus, in some instances, while we provide specific details regarding the Commission’s expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it. We find that this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification “that addresses a specific matter” if the Commission considers it appropriate to carry out section 215 of the FPA. In the Final Rule, we have considered commenter’s concerns and, where a directive for modification appears to be determinative of the outcome, the Commission provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to the Reliability Standard. Further, the Commission clarifies that, where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission’s underlying concern or goal as efficiently and effectively as the Commission’s proposal. Following the Commission’s guidance as stated in paragraph 186, the NSRS respectfully submits the above comments that are an equivalent alternative, thus providing an efficient and effective focus within the following mandatory reliability Standards.</p> <p>Response: Thank you for your comments. We will forward this to the Standards Committee for its consideration when assessing projects that address FERC directives. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p>
Florida Municipal Power Agency	Yes	<p>We applaud NERC in trying to address many of the FERC directives in Order 693. We remind NERC; however, of the language in the statute, FPA Section 215, that says: "The Commission shall give due weight to the technical</p>

Organization	Yes or No	Question 30 Comment
		<p>expertise of the Electric Reliability Organization ..." NERC ought to question the technical validity of some of the directives and not take FERC directives for granted. In the spirit of being constructive, NERC should offer more technically appropriate directives that address the Commissions concerns, hopefully in a better fashion than what the Commission directs.</p> <p><i>Response: Thank you for your comments. We will forward this to the Standards Committee for its consideration when assessing projects that address FERC directives.</i></p>
E.ON U.S.	Yes	<p>While E ON U.S. agrees with what NERC has identified as the motivation for this project, deviation from the standards development process in order to demonstrate work product is not likely to result in the creation of clear, reasonable, and quality standards and requirements.</p> <p><i>Response: Thank you for the support.</i></p>
Western Electricity Coordinating Council	Yes	<p>While this same effort could have occurred several years ago, I believe that NERC was trying to prioritize modifications based on impact to the BES. I believe the priorities were for the most part accurate and I commend NERC for their ongoing effort.</p> <p><i>Response: Thank you for the support.</i></p>

31. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration:

Some commenters suggested that the team should apply overall quality improvements more globally. Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.

Some commenters pointed out inconsistencies between standards and other efforts currently underway. However, based on the withdrawal of several changes originally proposed in this project, we believe those conflicts are no longer relevant.

Organization	Yes or No	Question 31 Comment
Ameren	No	
Arizona Public Service Company	No	
Consumers Energy Company	No	
Dominion	No	<p>While we are unaware of specific conflicts, we do see duplication between some reliability requirements and various the terms of tariffs and agreements (as examples; pro-forma Open Access Transmission Tariffs and Interconnection Service Agreements). We do not believe it necessary to have these in more than one place given that, at least in the US, FERC, in most cases, has jurisdiction over all of these and we question which prevails when conflicts arise.</p> <p>Response: Thank you for the comment. We are unable to determine which requirements are in more than one place so we would suggest the commenters to convey to the NERC Standards Manager some examples of such duplications.</p>
Dynergy Inc.	No	
Entergy Services	No	
Florida Municipal Power Agency	No	

Organization	Yes or No	Question 31 Comment
Georgia System Operations Corporation	No	None.
IESO	No	
Illinois Municipal Electric Agency	No	
Kansas City Power & Light	No	
NERC Standards Review Subcommittee	No	
Oklahoma Municipal Power Authority	No	
PacifiCorp	No	
Pepco Holdings, Inc. - Affiliates	No	
Santee Cooper	No	
SDG&E	No	
SERC OC Standards Review Group	No	
United Illuminating Company	No	
Western Electricity Coordinating Council	No	

Organization	Yes or No	Question 31 Comment
American Electric Power	Yes	<p>AEP does not agree with expanding the scope to the LSE in R5. Furthermore, the existing applicability to the PSE is not a reliability related requirement as this service is provided by the TSP by default.</p> <p>Response: We are unable to relate this comment to this question which deals specifically with conflicts with regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. Please see the response provided to Q28 (related to P1858) which addresses these comments with respect to the proposed changes to VAR-001.</p>
Central Lincoln	Yes	
Indiana Municipal Power Agency	Yes	<p>EOP-003 is currently in a draft phase under the UFLS project commenting and balloting phase.</p> <p>Response: This standard has been removed from consideration for balloting.</p>
Springfield Utility Board	Yes	<p>SUB's comments on proposed changes to the language on specific standards is reflective of inconsistencies in the original proposed language with regards to reliability, clarity, consistency. However, with some changes the proposed standards could remove those conflicts.</p> <p>Response: We are unable to relate this comment to the question which deals specifically with conflicts with regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. We suggest the commenters to contact the NERC Standards Manager to clarify this comment, if desired.</p>
US Bureau of Reclamation	Yes	<p>The process for modifying the standards was in accordance with the Standard Development Process.</p> <p>Response: Thank you.</p>
Midwest ISO Standards Collaborators	Yes	<p>NERC submitted an informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009.</p> <p>Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p>

Organization	Yes or No	Question 31 Comment
National Grid	Yes	<p>NERC submitted an informational filing on August 10, 2009 in response to the Commission’s ruling in Order 722. The proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009.</p> <p>Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p>
Northeast Power Coordinating Council	Yes	<p>NERC submitted an informational filing on August 10, 2009 in response to the Commission’s ruling in Order 722. The proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009.</p> <p>Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p>
Southern Company Transmission	Yes	<p>NERC submitted an informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Also, the recommended change to VAR-001, R9 seems to violate TPL-002. In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009.</p> <p>Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics</p>

Organization	Yes or No	Question 31 Comment
		<p>of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p> <p>We are not sure about the specific conflict between the proposed change to VAR-001, R9 and TPL-002. If the concern is with load shedding in VAR-001, R9, then this is no longer an issue since “load shedding” has been removed from that requirement.</p>

32. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed SAR or standards.

Summary Consideration:

Some commenters expressed a concern that this project was launched despite the fact that FERC has indicated that some of the directed changes should be considered as the standards are due for revision. We recognize this. Standards project priorities are driven by reliability needs, regulatory changes, and compliance issues that have surfaced and continue to surface. Adjustments to the 5-year cycle standards revision plan will be constant because of this. The Standards Committee felt that some of the directives could not be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was taken to identify and address those directives that appeared to require simple changes.

Some commenters raised a concern over the continued use of the subrequirement format and the poor quality of some of the existing standards, suggesting that the project should also be aimed at improving standard quality. Improving standard quality beyond that which is needed for the standard to be enforceable and responsive to the directive is outside of the scope of this project. In future standard revisions, we will make every attempt to apply additional improvements that have been identified through other efforts.

Some commenters disagree with the changes made to the Compliance Section on all involved standards, as doing so appears to be outside of the scope for this project. The compliance elements, which are not considered part of the standard, have been updated to reflect the current practices in use today. They do not conflict with the requirements, do not impose any new requirements, and should provide more clarity to entities wishing to comply with the standard. As such, the Response Team believes the updates are both appropriate and within scope.

Some commenters express a concern that approval of the redline changes to address the Order 693 directives may be construed as approving the entire standard. Approval of the individual line item is not construed to be approving the remaining part of the standard. For this reason, balloting is being conducted on a line-item basis, not on a per standard basis.

Organization	Question 32 Comment
Western Electricity Coordinating Council	<p>I still believe that the fill-in-the-blank standards need to be addressed to remove uncertainty in the application of these standards.</p> <p>Response: Thank you for the comment. The scope of this work is to address simple changes to comply with the directives. It does not include reviewing the appropriateness of fill-in-the-blank standards. We will forward this comment to the NERC Standards Committee for its consideration.</p>
Southern Company Transmission	<p>In every standard, the Compliance Monitoring Process has been modified. This was not identified in the scope of the SAR. Thus, these changes appear to exceed the scope of the SAR.</p> <p>Response: Paragraph 330 in Order 693 stipulates that “as identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance</p>

Organization	Question 32 Comment
	<p>monitor.” We interpret this to generally apply to all standards as otherwise, there would have been such an explicit directive for every standard covered in Order 693. While the SAR for this project did not explicitly state that all the standards included in the SAR would be changed to address this directive, the proposed work plan to address Paragraph 330 is deemed sufficient to cover modifications to the other standards as well. We do not believe that these changes are outside of the scope for this project.</p>
IESO	None
Springfield Utility Board	<p>SUB appreciates the work put into this process.</p> <p>Response: Thank you for the support.</p>
IRC Standards Review Committee	<p>Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties. Acceptance of any of the proposed changes included in this project is not meant to indicate concurrence with the non-redline text included in the remainder of the Standard. We understand that these are modification to the Version 0 Standards originally filed with FERC and it is widely recognized and understood that these Standard were flawed at the time of adoption and filing. Further, industry approval of these proposed changes must not be construed as approving either the requirement or the standards themselves. Approval must be limited to the ad hoc change itself.</p> <p>Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes.</p> <p>The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.</p> <p>Approval of the individual line item is not construed to be approving the remaining part of the standard. This is why balloting is conducted on a line-item basis, not on a per standard basis.</p>
Dominion	<p>We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. NERC submitted an informational filing on</p>

Organization	Question 32 Comment
	<p>August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.</p> <p>Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p> <p>For this set of changes, we have carefully reviewed the Measures, where their respective requirements have been modified, to ensure consistency. We thank you for making this suggestion.</p>
SERC OC Standards Review Group	<p>We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested.</p> <p>Response: Improving standard quality beyond that whi is required to be enforceable and to meet the directive is outside of the scope of this project,and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p> <p>For this set of changes, we have carefully reviewed the Measures, where their respective requirements have been modified, to ensure consistency. We thank you for making this suggestion</p>
SDG&E	<p>[1] For FAC-002, there are "subregional processes" at WECC region. For instance, for generator interconnection study, utilities within CAISO are doing study work for CAISO as subcontractor. The document requests should apply only CAISO.</p> <p>[2] For MOD-17, the standard should emphasize each entity has one designated function or group to provide "information". Current wording requests "load serving entity", "planning authority", "transmission planner", and "resource planner" shall each provide.....</p> <p>Response: We are unable to understand your concern since the proposed changes to FAC-002 invlove Requirement R1.4 and the Compliance Enforcement Authority and Process only, none of which touched on applicable entities. Please contact the NERC Standards Manager to clarify your concern as appropriate.</p> <p>MOD-017 has been removed from consideration for balloting. You comments on MOD-017 will be retained for future</p>

Organization	Question 32 Comment
	consideration.
Illinois Municipal Electric Agency	<p>Given the current avalanche of Reliability Standards Under Development, it is impossible for most municipal entities or a Joint Action Agency to adequately assess the implications of the numerous proposed revisions to existing reliability standards and proposed new reliability standards. A moratorium on standards development needs to be established until existing standards have gone through the results-based review.</p> <p>Response: We recognize the large volume of work ongoing today, and the staffing challenges that it presents. Unfortunately, it is not feasible to impose such a moratorium; progress to improve reliability must continue in tandem with our results-based initiatives.</p>
Midwest ISO Standards Collaborators	<p>In every standard, the Compliance Monitoring Process has been modified. This was not identified in the scope of the SAR. Thus, these changes appear to exceed the scope of the SAR.</p> <p>Response: Paragraph 330 in Order 693 stipulates that “as identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.” We interpret this to generally apply to all standards as otherwise, there would have been such an explicit directive for every standard covered in Order 693. While the SAR for this project did not explicitly state that all the standards included in the SAR would be changed to address this directive, the proposed work plan to address Paragraph 330 is deemed sufficient to cover modifications to the other standards as well. We do not believe that these changes are outside of the scope for this project.</p>
Indiana Municipal Power Agency	<p>In general, it seems like some new terms need to be defined or added to the functional model, such as Regional Entity and ERO. These changes may start here and need to be carried out through all NERC standards.</p> <p>Response: Thank you. We will forward this comment to the Functional Model Working Group.</p>
Ameren	<p>Since it is widely acknowledged that sub requirements are really sub-parts of the main requirement and not each individual requirement, the sub-requirements should be removed as part of these effort. The reason for our comment is supported by the new Reliability Standard Template available on the NERC site.</p> <p>Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system. However, this suggestion will be considered in other standard projects.</p>
Disturbance and Sabotage Reporting Drafting Team	<p>The DSR SDT requests that the Project 2010-12, Order 693 Directives SDT remove EOP-004 from its project. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) is currently revising the requirements of EOP-004. The timing of revisions, with two teams proposing revisions to the same standard in the same time frame, may lead to</p>

Organization	Question 32 Comment
	<p>stakeholder confusion and result in filing of competing standards with the FERC. The DSR SDT has many concerns with the proposed revisions to EOP-004 and the team is working to correct the deficiencies of the requirements. Examples of these deficiencies include 1) use of the word “promptly” in R2 and R3 (ambiguous); 2) having LSE an applicable entity (R3) since an LSE does not necessarily own assets; and 3) Continued use of the RRO in the requirements. The DSR SDT does not consider the proposed revisions to be “low hanging fruit”. The proposed revisions do address the explicit directives (paragraphs 612 and 615), but fail to provide needed clarity to the requirements. The DSR SDT requests that the Project 2010-12, Order 693 Directives SDT remove EOP-004 from its project.</p> <p>Response: Thank you. EOP-004 has been removed from consideration for balloting due to the reasons cited, and after consideration of other comments.</p>
<p>Georgia System Operations Corporation</p>	<p>The proposed SAR and standards resulting from the abbreviated development process are excellent examples of the value of the approved Standards Development Process and the inadvisability of taking shortcuts on that process. We believe that these revisions would have been much better implemented through the approved process and request that the ERO and the Standards Committee refrain from using an abbreviated process in the future.</p> <p>Response: Thank you for the support. The NERC SC recently discussed the use of expedited processes included in the approved standards development process. We believe the SC will continue to exercise its discretion on the best approach to take in response to directives or other urgent issues. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure that any proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.</p>
<p>E.ON U.S.</p>	<p>The section format / lettering of the standards is inconsistent. For example, BAL-002-1 and others have Introduction labeled as section “A” and Requirements as section “B” while others do not have a label for Introduction and have section “A” as Requirements. E ON U.S. suggests that a consistent format be used for all standards. In addition to the comments provided herein, E ON U.S. generally supports the comments submitted by both Midwest ISO and PJM Interconnection.</p> <p>Response: The purpose of this project is to expeditiously address outstanding directives with a limited amount of changes, leaving the objective of improving standard quality to future projects when the affected standards are due for revision. In future standard revisions, we will make every attempt to ensure consistent standard format/structure.</p>
<p>National Grid</p>	<p>There is a potential conflict with existing standards under development. Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties.</p> <p>Response: Thank you. All potential conflicts have been identified either at the pre-posting stage or during this commenting/balloting stage. Standard changes that could create a conflict with existing standard projects have been identified by the affected standards’ standard drafting teams and the Response Team. We believe all conflicts have been duly</p>

Organization	Question 32 Comment
	addressed.
Northeast Power Coordinating Council	<p>There is a potential conflict with existing standards under development. Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties. Acceptance of any of the proposed changes included in this project is not meant to indicate concurrence with the non-redline text included in the remainder of the standard. These are modifications to the Version 0 standards originally filed with FERC, and it is widely recognized and understood that these Standards were flawed at the time of adoption and filing.</p> <p>Response: Thank you. All potential conflicts have been identified either at the pre-posting stage or during this commenting/balloting stage. Standard changes that could create a conflict with existing standard projects have been identified by the affected standards' standard drafting teams and the Response Team. We believe all conflicts have been duly addressed.</p> <p>Approval of the individual line item is not construed to be approving the remaining part of the standard. This is why balloting is conducted on a line-item basis, not on a per standard basis.</p>
Entergy Services	<p>We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. NERC submitted an informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be and should not be done in the changes being undertaken to modify the standards at this time. In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009.</p> <p>Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach.</p>