NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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.

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

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

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

Index to Questions, Comments, and Responses

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 Councilq	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

		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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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	EEI	SERC	1, 5
11.	Andy Burch	EEI	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

		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 Utilties	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	6, 1, 3, 5

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Louis Slade	Dominion	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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	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	FRCC	1
3.	James Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utilities Authority	FRCC	4

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Terry Blackwell	Santee Cooper	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

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

6. Wayne Ahl		SERC	1, 9

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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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
5. Rod Lewis	KCPL	SPP	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
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 ingebrigtson	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						
33.	Individual	Laura Zotter	ERCOT ISO		x								

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

Summary Consideration:

Organization	Question 1
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
National Grid	
SDG&E	
CECD	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No

Organization	Question 1
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
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

Organization	Question 1
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)?

Summary Consideration:

Organization	Question 2
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
National Grid	
SDG&E	
Ameren	No
Arizona Public Service Company	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No

Organization	Question 2
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 Muncipal Power Authority	No
Pepco Holdings, Inc. - Affiliates	No
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

Organization	Question 2
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)?

Summary Consideration:

Organization	Question 3
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
National Grid	
SDG&E	
Ameren	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No

Organization	Question 3
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 Muncipal Power Authority	No
Santee Cooper	No
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

Organization	Question 3
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)?**

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
Illinois Municipal Electric Agency		
National Grid		
SDG&E		
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

Organization	Yes or No	Question 4 Comment
		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 modified outside the standards development process.Paragraph 321Taken 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 330Inserting 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). Paragraph 335We 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.Paragraph 1232The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose

Organization	Yes or No	Question 4 Comment
		(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 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.
Response:		
Xcel Energy	No	
Kansas City Power & Light	No	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.
Response:		
E.ON U.S.	No	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:Demand-Side Management (DSM): Activities undertaken by end-use customers, Load-Serving Entitiesor their agents or representatives to change electrical demand,

Organization	Yes or No	Question 4 Comment
		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.Operating Reserve - Spinning: The portion of Operating Reserve consisting of: 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.Operating Reserve - Supplemental: The portion of Operating Reserve consisting of: 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.
Response:		
Springfield Utility Board	No	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 permiates 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". SUB suggests that a better clarification would be to.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. NDDSM 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"

Organization	Yes or No	Question 4 Comment
		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 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."
Response:		
Entergy Services	No	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.”
Response:		
SERC OC Standards Review Group	No	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.”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.
Response:		
Santee Cooper	No	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.

Organization	Yes or No	Question 4 Comment
Response:		
Southern Company Transmission	No	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 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. 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 loadsParagraph 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.
Response:		
Ameren	No	Q.2 Comments - (a)In the definition of DSM, the parenthetical addes ambiguity. (b) Likewise, the implication that the DSM does not have to be controlled by an operator, means that DSM will not be comparabale, 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".Q.3 Comments - The existing definition of Contigency Reserve should be modified to state, "The portion of Operating Reserve used for responding to generation reporatble Disturbance".Q.4 Comments - (a) In R4.2, it should identify who (which group) at ERO; Enforcements, Stanadrds, Event Analysis? (b) What is the appeal process?
Response:		

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	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 CommitteeERO.” It is not enforceable or appropriate 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.
Response:		
ERCOT ISO	No	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.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.Q2 - The NERC Project 2007-05 Balancing Authority Controls is addressing reserves.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.pdfUnder 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.
Response:		
IESO	No	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. The word “Resource” should not be capitalized since it would imply a defined term.Paragraph 1232 directs the ERO to expand the

Organization	Yes or No	Question 4 Comment
		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. 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”. 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.
Response:		
Georgia System Operations Corporation	No	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: 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”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”.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” 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.”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.2f) We

Organization	Yes or No	Question 4 Comment
		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; or2h) 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.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.
Response:		
Midwest ISO Standards Collaborators	No	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.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.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. 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

Organization	Yes or No	Question 4 Comment
		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. 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.
Response:		
American Electric Power	Yes	
NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	
Consumers Energy Company	Yes	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.
Response:		

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Agency	Yes	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.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.
Response:		
Arizona Public Service Company	Yes	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 suggests using Direct Control Load Management instead of DSM for Spinning Reserves.
Response:		
Oklahoma Municipal Power Authority	Yes	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.Paragraph 330, 335: Spinning reserve should invlude only Direct Control Load Management.
Response:		
Indiana Municipal Power Agency	Yes	Question 1 - IMPA understands the use of ERO and Regional Entity; however, teh 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.Question 2 and 3 - Demand Side Management

Organization	Yes or No	Question 4 Comment
		encomposes many resources of which some can be diretly controlled and some cannot. The resources that can be directly controlled by an operator should be included in the contingency reserves.
Response:		
CECD	Yes	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.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.”
Response:		
US Bureau of Reclamation	Yes	The process to modify these standards is not following the accept andapproved process. The excuse that "FERC has expressed concern that industryand NERC have been less responsive than desired in providing a timelyresolution to those directives." offers no urgent or compelling reason for thisextraordinary step. It is suggested that NERC utilize the conventional standardmodification process for the changes requested by FERC.R4.2, 6.2. The last sentence "This period may be adjusted to better suit theneeds of an Interconnection based on analysis approved by the ERO." should beremoved. Modification to the standards would require the standard approvalprocess. To require that the ERO approve an analysis adds no improvement inreliability of the BES.
Response:		
Pepco Holdings, Inc. - Affiliates	Yes	The term “within the Disturbance Recovery Period following the contingency event” should be used to describe Demand Side Management Resources.
Response:		
Dominion	Yes	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

Organization	Yes or No	Question 4 Comment
		Management activity must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” 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.
Response:		

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)?

Summary Consideration:

Organization	Question 5
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
National Grid	
SDG&E	
Ameren	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No

Organization	Question 5
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Santee Cooper	No
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
Dynegy Inc.	Yes
Entergy Services	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes

Organization	Question 5
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
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)?

Summary Consideration:

Organization	Question 6
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
National Grid	
SDG&E	
US Bureau of Reclamation	
Ameren	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No

Organization	Question 6
IESO	No
Midwest ISO Standards Collaborators	No
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 Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes

Organization	Question 6
Santee Cooper	Yes
SERC OC Standards Review Group	Yes
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)?

Summary Consideration:

Organization	Question 7	Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Illinois Municipal Electric Agency		
National Grid		
SDG&E		
IRC Standards Review Committee		Paragraph 404 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

Organization	Question 7	Comment
		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. o The proposed change introduces an undefined term "common reference". 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."
Response:		
ERCOT ISO		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.
Response:		
Xcel Energy	No	
IESO	No	(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. (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. (3) For the first part of changes for

Organization	Question 7	Comment
		directive in Paragraph 420 involving defining ARC, please see our comment in (1), above.(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.
Response:		
Ameren	No	(a) The new definition introduces an acronym (ARC) that is already used by FERC for Aggregate Retail Customer(b) The proposed ARC definition should modify "Balancing Authority's interchange..." to "Balancing Authority Area's interchange ...", since BA does not have a schedulem rather a BAA does (e.g. one BA may operate multiple BAA). (c) In the Regulating Reserve definition add "to generation resources" between comparable and response in the last phrase. (d) In R5 - No regulating reserve should be on non-firm service (e) In R7, the team uses ARC but refers to generation.
Response:		
Georgia System Operations Corporation	No	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).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.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.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.
Response:		

Organization	Question 7	Comment
Pepco Holdings, Inc. - Affiliates	No	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.
Response:		
E.ON U.S.	No	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. 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.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."
Response:		
Florida Municipal Power Agency	No	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.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.
Response:		
Northeast Power Coordinating Council	No	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."
Response:		

Organization	Question 7	Comment
Santee Cooper	No	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.
Response:		
Dominion	No	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.”
Response:		
Entergy Services	No	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.
Response:		
SERC OC Standards Review Group	No	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.”
Response:		
Midwest ISO Standards Collaborators	No	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

Organization	Question 7	Comment
		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 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.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. 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.
Response:		
US Bureau of Reclamation	No	The term "AGC" is used throught industry and the Reliability Standards.Unless the other standards are modified under this project, it is suggested that itwould be more expedient to modify the term AGC to allow for oher resources tobe included and not worry about the Generation part of the term. This will avoidconfusion with other standards, criteria, and procedures.In addition the definition cannot include all resources, just those that arecontrollable.The Definition should be rewritten as "Automatic Generation Control (AGC):Automatic adjustment of generation and other controllable resources in aBalancing Authority Area to maintain the Balancing Authority’s interchangeschedule plus Frequency Bias. ARC may also accommodate automaticinadvertent 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 arecontrollable.The Definition should be rewritten as "Automatic Generation Control (AGC):Automatic adjustment of generation and other controllable resources in aBalancing Authority Area to maintain the Balancing Authority’s interchangeschedule plus Frequency Bias. ARC may also accommodate

Organization	Question 7	Comment
		automaticinadvertent payback and time error correction."Examples of other Standards that use the term AGC include BAL 003, 004,005, 006, and BAL-Std-002.
Response:		
Springfield Utility Board	No	The use of the term "Demand Side Management" is overly broad, may lead to confusion with regard to application of standards, and confustion may reduce reliabilityThe 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 characteristics.(Please refer to comments on BAL-002-1)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.
Response:		
American Electric Power	Yes	
Arizona Public Service Company	Yes	
CECD	Yes	
Dynegy Inc.	Yes	
Kansas City Power & Light	Yes	
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	
NERC Standards Review Subcommittee	Yes	#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

Organization	Question 7	Comment
		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.
Response:		
PacifiCorp	Yes	1. The word “compromised” under Regulating Reserve definition should be changed to “comprised”.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.3. R5 -Request clarification of “transmission constraints”.4. R7-modify the following: “manual control to adjust generation resources to maintain the Net Scheduled Interchange”.
Response:		
Southern Company Transmission	Yes	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.Paragraph 415 - Taken from previously posted interpretation in Appendix 1.Paragraph 420 - Seems reasonable to have a backup plan for lost regulation service due to transmission constraints.
Response:		
Oklahoma Muncipal Power Authority	Yes	Paragraph 404: Regulation Reseve should only include Direct Control Load Management.
Response:		
Consumers Energy Company	Yes	Please provide your opinion regarding the Paragraph 404 VSL changes: In Favor Changes for directives in Paragraph 415: Disapprove Comments: In R17, the phrase "or frequency information to the operator" should be deleted as an unnecessary expansion of scope.Please provide your opinion regarding the Paragraph 415 VSL changes: In Favor Changes for directives in Paragraph 420: Approve Please provide your opinion regarding the Paragraph 420 VSL changes: In Favor

Organization	Question 7	Comment
Response:		
Indiana Municipal Power Agency	Yes	Question 5 - Regulating Reserve should not include just any type of DSM. Only the controlled forms of DSM should be included in Regulating Reserves.
Response:		

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)?

Summary Consideration:

Organization	Question 8
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
SDG&E	
US Bureau of Reclamation	
Ameren	No
Consumers Energy Company	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No

Organization	Question 8
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
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 Muncipal Power Authority	Yes
PacifiCorp	Yes

Organization	Question 8
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)?

Summary Consideration:

Organization	Yes or No	Question 9 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
Illinois Municipal Electric Agency		
SDG&E		
US Bureau of Reclamation		
IRC Standards Review Committee		Paragraph 565Although 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

Organization	Yes or No	Question 9 Comment
		in the next iteration of this Standard.Paragraph 571The 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.
Response:		
NERC Standards Review Subcommittee	No	#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 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.
Response:		
Ameren	No	(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 dealy with as an emergency due to insufficient generation either way. (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 calender quarter one year after approval, no extra reviews/update would be necessary. (c) R1 should include the recent interpretation. (d) R2.1 should add "inability of DSM to perform" after insufficient generating capacity (e) R2.1 - lack of transmission is undefined. Is this for n-1, n-2 or for n-7 events? (f) Attachmnet 1 needs to add a new item #16 - Consideration of DSM performance (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 nubers are consistent with the current VSL if the rounding is down.

Organization	Yes or No	Question 9 Comment
Response:		
Georgia System Operations Corporation	No	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.”
Response:		
Florida Municipal Power Agency	No	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 fo 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 ...
Response:		
National Grid	No	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.
Response:		
Xcel Energy	No	On 571, Xcel Energy couldn't find any reference to Para 571 in EOP-001.
Response:		
Entergy Services	No	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.”
Response:		
SERC OC Standards Review	No	Paragraph 571 - We suggest that R2.1 be re-written as follows: “Develop maintain and implement a set of

Organization	Yes or No	Question 9 Comment
Group		plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand.”
Response:		
Southern Company Transmission	No	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.”
Response:		
E.ON U.S.	No	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.
Response:		
Oklahoma Municipal Power Authority	No	Paragraph 571: Specific responsibilities should be better defined. i.e., R.2.1 - BA; R2.2 - TOP; R2.3 - TOP & BA; R2.4 - TOP
Response:		
ERCOT ISO	No	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.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.
Response:		
Indiana Municipal Power Agency	No	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.

Organization	Yes or No	Question 9 Comment
Response:		
United Illuminating Company	No	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. We suggest changing the edit to: ....Operating emergencies for: 2.1.1 insufficient generation capacity 2.1.2. A lack of transmission capability 2.1.3 A lack of transmission capability while executing a plan responding to a generation emergency
Response:		
Midwest ISO Standards Collaborators	No	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 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 it generating fleet, purchases, sales and ability to receive those sales. There are many reasons collectively that a BA may experience an operating emergency due 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.
Response:		

Organization	Yes or No	Question 9 Comment
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	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."
Response:		
Consumers Energy Company	Yes	Please provide your opinion regarding the Paragraph 565 VSL changes: Opposed Comments: 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. Changes for directives in Paragraph 571: Approve Comments: We recommend changing "insufficient generating capacity" to "insufficient resource capacity"
Response:		
Western Electricity Coordinating Council	Yes	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 clairify the applicable TOP and BA are the appropriate party

Organization	Yes or No	Question 9 Comment
		to determine which applicable elements in Attachment 1-EOP-001-0 are appropriate to consider when developing an emergency plan.
Response:		
Pepco Holdings, Inc. - Affiliates	Yes	The change did not clarify or enhance the requirement
Response:		
Northeast Power Coordinating Council	Yes	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.
Response:		
IESO	Yes	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" ad "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.
Response:		

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

Summary Consideration:

Organization	Question 10
Arizona Public Service Company	
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Florida Municipal Power Agency	
Illinois Municipal Electric Agency	
Indiana Municipal Power Agency	
IRC Standards Review Committee	
Oklahoma Muncipal Power Authority	
SDG&E	
Springfield Utility Board	
US Bureau of Reclamation	
Western Electricity Coordinating Council	

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
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

Organization	Question 10
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)?

Summary Consideration:

Organization	Question 11
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
SDG&E	
Springfield Utility Board	
US Bureau of Reclamation	
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
IESO	No

Organization	Question 11
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
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

Organization	Question 11
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
United Illuminating Company	Yes
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)?

Summary Consideration:

Organization	Yes or No	Question 12 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
Illinois Municipal Electric Agency		
SDG&E		
US Bureau of Reclamation		
IRC Standards Review Committee		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.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? 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

Organization	Yes or No	Question 12 Comment
		because:R4, R5, R6 are examples of requirements that need a major rewriting, or at least major discussion. 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!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-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.R6 is unclear. What constitutes “immediately”? If all remedies are optional, then no remedy is required, making compliance a moot point.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 “...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.”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.
Response:		
Xcel Energy	No	
NERC Standards Review Subcommittee	No	#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 applicable entities per

Organization	Yes or No	Question 12 Comment
		NERC definition.
Response:		
Ameren	No	(a) R 6.8 - Unknown technologies are not "technically feasible". Delete this sub requirement. (b) In Attachment 1, Alert 1 - does "All Available Resources" include DSM? If resources are comparable, why woudn't it be?
Response:		
Kansas City Power & Light	No	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 . . .”.
Response:		
National Grid	No	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.
Response:		

Organization	Yes or No	Question 12 Comment
E.ON U.S.	No	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.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: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.
Response:		
Southern Company Transmission	No	Paragraph 577 - Addressed in IRO-006. Does something need to be filed with NERC or FERC to explain that?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. 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
Response:		
Springfield Utility Board	No	Please refer to BAL-002 and BAL-005 commentsR6.3 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. Demand Side Management should be changed to Dispatchable Demand Side Management.This should be changed toR6.3 is proposed to state "R6.3. Deploying all available Dispatchable Demand Side Management (DDSM) options,"
Response:		
ERCOT ISO	No	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.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,

Organization	Yes or No	Question 12 Comment
		which needs to be in sync with the effort of the Demand Response Data Availability System (DADS) team.
Response:		
Midwest ISO Standards Collaborators	No	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. 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 changes to measures through an expedited process.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: "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. (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 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

Organization	Yes or No	Question 12 Comment
		Commission its course of action would be.
Response:		
Northeast Power Coordinating Council	No	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. 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.
Response:		
American Electric Power	Yes	
Arizona Public Service Company	Yes	
CECD	Yes	
Consumers Energy Company	Yes	
Oklahoma Muncipal Power Authority	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	

Organization	Yes or No	Question 12 Comment
Santee Cooper	Yes	
United Illuminating Company	Yes	
PacifiCorp	Yes	1. R6.8 Internal comment---This requirement illustrates the need for additional DSM resources. 2. M5-Request clarification.
Response:		
Georgia System Operations Corporation	Yes	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.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.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.
Response:		
Florida Municipal Power Agency	Yes	For Paragraph 577, we "ABSTAIN", as we do not understand why this is being balloted since there is no change
Response:		
Dominion	Yes	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:		
Entergy Services	Yes	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:		
SERC OC Standards Review Group	Yes	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.

Organization	Yes or No	Question 12 Comment
Response:		
Indiana Municipal Power Agency	Yes	Question 10 - Abstain. If this issue has been addressed, why is it being covered in this area of commenting?
Response:		
Western Electricity Coordinating Council	Yes	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 the appropriate party to determine which actions are appropriate.
Response:		
IESO	Yes	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.”
Response:		

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)?

Summary Consideration:

Organization	Question 13
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
Illinois Municipal Electric Agency	
IRC Standards Review Committee	
SDG&E	
Springfield Utility Board	
US Bureau of Reclamation	
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Consumers Energy Company	No

Organization	Question 13
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
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 Muncipal Power Authority	No
PacifiCorp	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No

Organization	Question 13
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)?

Summary Consideration:

Organization	Yes or No	Question 14 Comment
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
Illinois Municipal Electric Agency		
SDG&E		
Springfield Utility Board		
US Bureau of Reclamation		
IRC Standards Review Committee		Paragraph 601Taken 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. 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”?Paragraph 603The 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. Requirement R8 as written goes outside of the scope of the directive.Requirement R9 is

Organization	Yes or No	Question 14 Comment
		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 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. 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.
Response:		
NERC Standards Review Subcommittee	No	#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:R3. Each Transmission Operator and Balancing Authority shall coordinate manual load shedding plans with at least one of the following:R3.1 Physically connected Transmission Operators and Balancing Authorities orR3.2 Regional Entities within whose regions they operate orR3.3 Reliability Coordinator(s) associated with overseeing the operations of the Balancing Authority Area or Transmission Operator Area andR3.4 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. #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 "At least annually, each Transmission Operator and Balancing Authority shall simulate load shedding as stated within their respected load shedding plan". This rewrite will enable the TOP or BA to simulate load shedding as they plan, not practice load shedding by the use of simulation. #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

Organization	Yes or No	Question 14 Comment
		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 a modification to EOP-003-1 through the Reliability Standards development process that: (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 (2) requires periodic drills of simulated load shedding". R9 does not address the Commissions interests.
Response:		
Ameren	No	(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 (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 vauge.
Response:		
Northeast Power Coordinating Council	No	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.
Response:		
Georgia System Operations Corporation	No	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?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.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

Organization	Yes or No	Question 14 Comment
		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.14c) It isn't clear what Measure M2 refers to now. The VSL requirement changes appear to be mis-numbered.
Response:		
National Grid	No	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.
Response:		
Western Electricity Coordinating Council	No	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.
Response:		
Arizona Public Service Company	No	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.

Organization	Yes or No	Question 14 Comment
Response:		
Consumers Energy Company	No	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. 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. 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. 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.
Response:		
Kansas City Power & Light	No	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

Organization	Yes or No	Question 14 Comment
		identified.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?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.
Response:		
Florida Municipal Power Agency	No	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.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 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).

Organization	Yes or No	Question 14 Comment
Response:		
E.ON U.S.	No	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.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.There are errors in the numbering for VSLs R8, R9, and R10. There is no R10 in the Requirements Section.
Response:		
Dominion	No	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. 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.
Response:		
Entergy Services	No	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. 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.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.

Organization	Yes or No	Question 14 Comment
Response:		
SERC OC Standards Review Group	No	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. 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.
Response:		
Southern Company Transmission	No	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. 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.
Response:		
Santee Cooper	No	Paragraph 601 - the meaning of “coordinate” needs to be clarified. 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. 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.

Organization	Yes or No	Question 14 Comment
Response:		
American Electric Power	No	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. Furthermore, the addition of R9 does not seem to be justified as part of the FERC directive in Paragraph 603.
Response:		
Central Lincoln	No	Project 2007-01 is also rewriting this standard, and the two versions conflict.
Response:		
ERCOT ISO	No	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.-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. Requirement R8 as written goes outside of the scope of the directive.R9 is not asked for by the directive.
Response:		
Indiana Municipal Power Agency	No	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.Question 14 - The Commission is looking to have perodic drills of

Organization	Yes or No	Question 14 Comment
		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.
Response:		
CECD	No	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."
Response:		
United Illuminating Company	No	R3 should specify it is manual load shedding or operator initiated loadhedding, so as not to be confused with ufls, uvls, or sps. 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. 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.
Response:		
Oklahoma Municipal Power Authority	No	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.
Response:		
PacifiCorp	No	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) .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.
Response:		

Organization	Yes or No	Question 14 Comment
IESO	No	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.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. 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 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. 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. 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.
Response:		
Midwest ISO Standards Collaborators	No	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

Organization	Yes or No	Question 14 Comment
		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.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.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 Commissions 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 Commissions directives and understanding of the UFLS standards in Order 693.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.
Response:		
Pepco Holdings, Inc. - Affiliates	Yes	
Xcel Energy	Yes	

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)?

Summary Consideration:

Organization	Question 15
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
IRC Standards Review Committee	
SDG&E	
US Bureau of Reclamation	
Ameren	No
American Electric Power	No
CECD	No
Central Lincoln	No
Consumers Energy Company	No
Dynegy Inc.	No
E.ON U.S.	No
ERCOT ISO	No

Organization	Question 15
Georgia System Operations Corporation	No
Illinois Municipal Electric Agency	No
Indiana Municipal Power Agency	No
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 Muncipal Power Authority	Yes

Organization	Question 15
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
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)?

Summary Consideration:

Organization	Yes or No	Question 16 Comment
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
SDG&E		
IRC Standards Review Committee		Paragraph 612Taken 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.Paragraph 615The 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.
Response:		
ERCOT ISO		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.
Response:		
Indiana Municipal Power Agency		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).Question 16 - Abstain. IMPA is not sure if the Xcel concern

Organization	Yes or No	Question 16 Comment
		has been addressed and cleared up entirely.
Response:		
Central Lincoln		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.
Response:		
Xcel Energy	No	
Dynegy Inc.	No	#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 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.#16 - Attachment 1 was already part of the Standard thus just referencing Attachment 1 does not address Xcel's request.
Response:		
Ameren	No	(a) R3 - nalyze disturbance on GOP system is unclear or vauge. Drafting team should describe what is expected. (b) R3.1 - "analyze performance of their equipment" is vauge. Drafting team should describe what is expected or delete the requirement. (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.
Response:		
Northeast Power Coordinating Council	No	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

Organization	Yes or No	Question 16 Comment
		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?
Response:		
E.ON U.S.	No	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.In paragraph 615, 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.It is unclear how the insertion in R4 clarifies the definition of a reportable “event” as the standard references a reportable “incident.”
Response:		
Florida Municipal Power Agency	No	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 for each entity that has reporting obligations." 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.
Response:		
National Grid	No	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

Organization	Yes or No	Question 16 Comment
		listed in Attachment 1.
Response:		
Southern Company Transmission	No	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. 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.Paragraph 615 - Not low hanging fruit.
Response:		
American Electric Power	No	Paragraph 612There 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, "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."Paragraph 615R4 needs to include the Distribution Provider since it was added to R3.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 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. 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. Additionally the VSL for R2 in the current standard should be revised to remove reference to the Generator Operator.The last sentence of Measures M2 and M3 each need to be revised to reference Requirements 4.1 and 4.3, respectively.
Response:		
Oklahoma Municipal Power Authority	No	Paragraph 615: Attachment 1 should be revised to clarify which Functional Entities are responsible for each type of reportable event.

Organization	Yes or No	Question 16 Comment
Response:		
CECD	No	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.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".
Response:		
US Bureau of Reclamation	No	The generator operators in WECC provide disturbance reports to WECC. Thenew requirement provides the information to TOP, BA, and RC. This standardrequires far too many reports. Reports are sent to WECC, NERC, DOE and nowthe TOP and BA. It is not clear what benefit will be derived by this redundantrequirement. The requirement should be limited to analyzing the events andproviding reports upon request. WECC already has a disturbance reporting andanalysis process to ensure BES issues are addressed. In addition the entitiesmust analyze protection system operations in PRC-004.It is interesting that the COmmission continues to ensure unilateralcommunication among the entities by not requiring TOP and BA to share theirdisturbance reports with the GOP, DP, and LSE's.
Response:		
United Illuminating Company	No	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?
Response:		
Midwest ISO Standards Collaborators	No	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 be handled through a

Organization	Yes or No	Question 16 Comment
		variance as stated in NERC's comments. As a result, we do not believe the directives in paragraph 615 are fully addressed. 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.
Response:		
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	#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.

Organization	Yes or No	Question 16 Comment
Response:		
Georgia System Operations Corporation	Yes	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: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.Also, as a general statement this standard refers to Regional Reliability Organization instead of Regional Entity.The Measures refer to Requirements R3.1 and R3.3. We believe they should refer to R4.1 and R4.3 now.
Response:		
Consumers Energy Company	Yes	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.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

Organization	Yes or No	Question 16 Comment
		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.
Response:		
Kansas City Power & Light	Yes	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.
Response:		
Illinois Municipal Electric Agency	Yes	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?
Response:		
Santee Cooper	Yes	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 equipment and provide all requested information

Organization	Yes or No	Question 16 Comment
		necessary to analyze BES disturbances."
Response:		
Western Electricity Coordinating Council	Yes	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. Promply needs to be clarified, considereing differnet time frames for differning types of events.
Response:		

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)?

Summary Consideration:

Organization	Yes or No	Question 17 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Springfield Utility Board		
IRC Standards Review Committee		Paragraph 693Taken 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. 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.
Response:		
E.ON U.S.	No	
Xcel Energy	No	
Consumers Energy Company	No	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.

Organization	Yes or No	Question 17 Comment
Response:		
Kansas City Power & Light	No	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 included in the proposed change for R1.4.
Response:		
ERCOT ISO	No	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: “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.”
Response:		
US Bureau of Reclamation	No	The requirement cites TPL-001 through 003 which do not apply to GO's. Themodification makes matters worse in that the GO is now required to analyzesystem performance under contigency conditions. This is normally performed bythe TP.
Response:		
Midwest ISO Standards Collaborators	No	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.”
Response:		
Ameren	Yes	
American Electric Power	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 17 Comment
CECD	Yes	
Dominion	Yes	
Dynegy 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 Muncipal Power Authority	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Santee Cooper	Yes	
SDG&E	Yes	

Organization	Yes or No	Question 17 Comment
SERC OC Standards Review Group	Yes	
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	
Georgia System Operations Corporation	Yes	None.
Southern Company Transmission	Yes	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.”
Response:		

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)?

Summary Consideration:

Organization	Question 18
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
IRC Standards Review Committee	
US Bureau of Reclamation	
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

Organization	Question 18
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No
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

Organization	Question 18
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
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)?

Summary Consideration:

Organization	Question 19
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
IRC Standards Review Committee	
US Bureau of Reclamation	
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

Organization	Question 19
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No
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

Organization	Question 19
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
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)?

Summary Consideration:

Organization	Question 20
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
IRC Standards Review Committee	
US Bureau of Reclamation	
Ameren	No
American Electric Power	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No

Organization	Question 20
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal 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

Organization	Question 20
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes
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)?

Summary Consideration:

Organization	Question 21
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
IRC Standards Review Committee	
US Bureau of Reclamation	
Ameren	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No

Organization	Question 21
IESO	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No
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

Organization	Question 21
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes
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)?

Summary Consideration:

Organization	Yes or No	Question 22 Comment
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
US Bureau of Reclamation		
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?
Response:		
IRC Standards Review Committee		Paragraph 1249 & 1250The 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: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 time2. 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

Organization	Yes or No	Question 22 Comment
		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 but not a good reason to mandate data.5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.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.Paragraph 1252 & 1255There are several issues with the accuracy proposal: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.

Organization	Yes or No	Question 22 Comment
Response:		
Illinois Municipal Electric Agency		What will this additional data reporting accomplish? Has a problem ben 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.
Response:		
Xcel Energy	No	
IESO	No	(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. (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).(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 it 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.
Response:		

Organization	Yes or No	Question 22 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.
Response:		
Ameren	No	All referenced requirements need to explicitely 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.
Response:		
Kansas City Power & Light	No	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 subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Response:		
Florida Municipal Power Agency	No	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 to 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.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.

Organization	Yes or No	Question 22 Comment
		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.
Response:		
National Grid	No	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.
Response:		
Oklahoma Municipal Power Authority	No	Paragraph 1251: Remove Day-ahead hourly forecasts from R1.5 to be consistent with the rest of the standard; specifically, R1.3. Paragraph 1255: Transmission Planners should not be responsible for load forecasting. Load forecasting is completed by other entities and submitted to Transmission Planners.
Response:		
Dominion	No	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: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,

Organization	Yes or No	Question 22 Comment
		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 iscurrently 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.
Response:		
Entergy Services	No	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

Organization	Yes or No	Question 22 Comment
		models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.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.
Response:		
SERC OC Standards Review Group	No	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.-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.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.
Response:		
Midwest ISO Standards Collaborators	No	While the proposed changes may meet directives in paragraph 1249 and 1250, we do not believe this represents the solution that is needed. 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

Organization	Yes or No	Question 22 Comment
		requirements to assess accuracy. 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? 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. 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. 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 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.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.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 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.
Response:		
Southern Company Transmission	No	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.

Organization	Yes or No	Question 22 Comment
		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. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.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.
Response:		
CECD	Yes	
Springfield Utility Board	Yes	
NERC Standards Review Subcommittee	Yes	#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.
Response:		
Northeast Power Coordinating	Yes	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the

Organization	Yes or No	Question 22 Comment
Council		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. General comment - Each entity's expertise should be relied upon to gather the appropriate weather information.4. In Requirement R1.5 - What is meant by "biasing of each load forecast"?5. With respect to Requirement R1.5 - Is this applicable to Demand Response?6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 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. 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.
Response:		
Georgia System Operations Corporation	Yes	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.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:18c) The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its Load forecast process to improve accuracy as necessary.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.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.
Response:		
Consumers Energy Company	Yes	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 Please provide your opinion regarding the Paragraph 1250 VSL changes: In Favor Changes for directives in Paragraph 1251: Disapprove Comments: R1.5 includes a requirement for "Day-ahead Hourly . . . load Forecast accuracy . . .". This seems

Organization	Yes or No	Question 22 Comment
		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 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) 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.
Response:		
Arizona Public Service Company	Yes	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).
Response:		
SDG&E	Yes	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).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.
Response:		
American Electric Power	Yes	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:1. It is unclear what reliability objective is being served. If this data is for NERC to

Organization	Yes or No	Question 22 Comment
		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 report wide-area assessments to NERC.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.
Response:		
ERCOT ISO	Yes	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.Q19 - See Q18 comments immediately above.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.
Response:		
Indiana Municipal Power Agency	Yes	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.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.
Response:		

Organization	Yes or No	Question 22 Comment
PacifiCorp	Yes	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. 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????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, temperature and humidity data for the prior year used to normalize demands.
Response:		
Western Electricity Coordinating Council	Yes	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: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. 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.
Response:		
United Illuminating Company	Yes	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.
Response:		

Organization	Yes or No	Question 22 Comment
Pepco Holdings, Inc. - Affiliates	Yes	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.
Response:		
E.ON U.S.	Yes	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.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. 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.â€ƒ
Response:		

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)?

Summary Consideration:

Organization	Question 23
Central Lincoln	
central Maine Power Company	
Disturbance and Sabotage Reporting Drafting Team	
Dynegy Inc.	
IRC Standards Review Committee	
US Bureau of Reclamation	
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

Organization	Question 23
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal 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

Organization	Question 23
IESO	Yes
Illinois Municipal Electric Agency	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
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)?

Summary Consideration:

Organization	Yes or No	Question 24 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
US Bureau of Reclamation		
IRC Standards Review Committee		Paragraph 1276Taken 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. Paragraph 1277Specific 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.
Response:		

Organization	Yes or No	Question 24 Comment
Xcel Energy	No	
NERC Standards Review Subcommittee	No	#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 a entity "failed to make improvements to improve accuracy", is unrealistic.
Response:		
IESO	No	(1) Specific to the proposed changes to address the directive in Paragraph 1276, we generally agree with the changes to R1. (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 it 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?
Response:		
Ameren	No	(a) R1.1 - Add ",DSM," after interruptible demands (b) R2 - what is the basis for 10%?
Response:		

Organization	Yes or No	Question 24 Comment
Northeast Power Coordinating Council	No	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.
Response:		
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.
Response:		
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.
Response:		
Consumers Energy Company	No	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? 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

Organization	Yes or No	Question 24 Comment
		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.
Response:		
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 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.
Response:		
E.ON U.S.	No	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: “Forecasts of interruptible demands and Direct Control Load

Organization	Yes or No	Question 24 Comment
		Management (DCLM) as contained in the documentation for MOD16-1for summer and winter peak system conditions."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.
Response:		
Florida Municipal Power Agency	No	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.
Response:		
SDG&E	No	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. 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% variance, and we should not have to develop a method to put us closer to our forecast. We may also want to suggest that NERC is confusing a planning forecast with an operating forecast, which are two separate environments.
Response:		
Oklahoma Municipal Power Authority	No	It is not clear how the requirements in R2 are to be accomplished.
Response:		

Organization	Yes or No	Question 24 Comment
Georgia System Operations Corporation	No	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.
Response:		
National Grid	No	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.
Response:		
Southern Company Transmission	No	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. 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. 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.
Response:		
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

Organization	Yes or No	Question 24 Comment
		enhance reliability.
Response:		
Dominion	No	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. 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.
Response:		
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.
Response:		
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.
Response:		
American Electric Power	No	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). Secondly, “biasing of each forecast” is not appropriate phrasing. Loads are forecast to be as accurate as possible without bias.

Organization	Yes or No	Question 24 Comment
		A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias.
Response:		
Springfield Utility Board	No	SUB respectfully disagress 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 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. 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 DLCM.2) Create a new standard for Interuptible Demands with lower severity levels and requirements to remove barriers for entry.
Response:		
United Illuminating Company	No	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

Organization	Yes or No	Question 24 Comment
Response:		
Midwest ISO Standards Collaborators	No	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 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.
Response:		
Entergy Services	No	While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Response:		
CECD	Yes	
Illinois Municipal Electric Agency	Yes	
Western Electricity Coordinating Council	Yes	
PacifiCorp	Yes	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.

Organization	Yes or No	Question 24 Comment
Response:		
Pepco Holdings, Inc. - Affiliates	Yes	the directive has been met by the changes, the world has advanced since Order 693, and this is not needed.
Response:		

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)?

Summary Consideration:

Organization	Yes or No	Question 25 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
US Bureau of Reclamation		
Ameren		(a) R1 and R2.1 - Add ",DSM," after interruptible demands
Response:		
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.
Response:		

Organization	Yes or No	Question 25 Comment
E.ON U.S.	No	
National Grid	No	
Xcel Energy	No	
Northeast Power Coordinating Council	No	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.
Response:		
Kansas City Power & Light	No	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 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.

Organization	Yes or No	Question 25 Comment
Response:		
Florida Municipal Power Agency	No	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.
Response:		
Oklahoma Municipal Power Authority	No	It is not clear on how the requirements in R2 are to be accomplished.
Response:		
Dominion	No	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 loadIt should also be noted than 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.
Response:		
Entergy Services	No	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.
Response:		
SERC OC Standards Review Group	No	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

Organization	Yes or No	Question 25 Comment
		and demand side response is typically not metered separate from the base load.
Response:		
Southern Company Transmission	No	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.
Response:		
Santee Cooper	No	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.
Response:		
ERCOT ISO	No	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.
Response:		
Indiana Municipal Power Agency	No	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 interruptable demand, and compare it against an hour without DCLM and interruptable 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 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 1. The ERO and Regional Entity can get the information formt eh Transmission Operator, Balancing Authority, or Reliablity Coordinator which is the way some regions are currently gathering this information.
Response:		

Organization	Yes or No	Question 25 Comment
Pepco Holdings, Inc. - Affiliates	No	R1 has been appropriately changed; R2 does not need to include the ERO
Response:		
American Electric Power	No	R2.1 "...biasing of each forecast" is not appropriate phasing. 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.
Response:		
Springfield Utility Board	No	SUB respectfully disagress 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 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. 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 DLCM.2) Create a new standard for Interuptible Demands with lower severity levels and requirements to remove barriers for entry.

Organization	Yes or No	Question 25 Comment
Response:		
Midwest ISO Standards Collaborators	No	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. 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. 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.
Response:		
IESO	No	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.
Response:		
Arizona Public Service Company	Yes	
CECD	Yes	
NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
SDG&E	Yes	

Organization	Yes or No	Question 25 Comment
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	
Illinois Municipal Electric Agency	Yes	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.
Response:		
Consumers Energy Company	Yes	Please provide your opinion regarding the Paragraph 1287 VRF and VSLs: In Favor
Response:		
Georgia System Operations Corporation	Yes	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.
Response:		

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)?

Summary Consideration:

Organization	Yes or No	Question 26 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
Dynegy Inc.		
US Bureau of Reclamation		
Northeast Power Coordinating Council	No	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.
Response:		
Ameren	Yes	
American Electric Power	Yes	
Arizona Public Service Company	Yes	
CECD	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 26 Comment
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	
IRC Standards Review Committee	Yes	
Kansas City Power & Light	Yes	
National Grid	Yes	
NERC Standards Review Subcommittee	Yes	
Oklahoma Muncipal Power Authority	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 26 Comment
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	None.
Midwest ISO Standards Collaborators	Yes	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.
Response:		

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)?

Summary Consideration:

Organization	Yes or No	Question 27 Comment
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
SDG&E		
IRC Standards Review Committee		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: 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.
Response:		
NERC Standards Review Subcommittee	No	#27. FERC Order 693 does not state that “individually or jointly” entities that own a Protection System shall analyze and develop a 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”.

Organization	Yes or No	Question 27 Comment
Response:		
Ameren	No	(a) The Glossary of Terms still uses RRO, why the change to Regional Entity? (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. (c) We do not believe that LSE and TOP would own Protection Systems. The standard should not apply to LSE and TOP.
Response:		
Northeast Power Coordinating Council	No	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. 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. R3 should be reworded to reflect RE just like the other requirements have been modified.
Response:		
Consumers Energy Company	No	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.
Response:		
Kansas City Power & Light	No	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

Organization	Yes or No	Question 27 Comment
		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.
Response:		
Georgia System Operations Corporation	No	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.
Response:		
American Electric Power	No	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

Organization	Yes or No	Question 27 Comment
		problem. We recommend that any entity 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. 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..." 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...". Also, note that “Regional Reliability Organization” should actually be “Regional Entity”.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."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."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."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..."
Response:		
Central Lincoln	No	It remains unclear how an entity can comply with any of the requirements in the absence of a Regional Entity procedure.
Response:		
Entergy Services	No	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 R1.2 and R1.3 should be included in this standard. Likewise, we do not believe that R3.2 and R3.3 should be included in this standard.

Organization	Yes or No	Question 27 Comment
Response:		
SERC OC Standards Review Group	No	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.
Response:		
Midwest ISO Standards Collaborators	No	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.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.
Response:		
Pepco Holdings, Inc. - Affiliates	No	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. 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.

Organization	Yes or No	Question 27 Comment
Response:		
PacifiCorp	No	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.
Response:		
ERCOT ISO	No	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.
Response:		
E.ON U.S.	No	The FERC's directive is to change references from RRO to RE. R3, M1,M2 and M3 still reference RRO.
Response:		
United Illuminating Company	No	United Illuminating believes the transmission owner should be listed in the sub bullet 1.1. R1 should start "Any entity listed below that individually or jointly...". Same comment for R3.United Illuminating points out to the Drafting Team that Paragraph 1469 also refers this change to PRC-005, 8, 11, 15, 16, 17, 21.
Response:		

Organization	Yes or No	Question 27 Comment
IESO	No	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 secures 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.We suggest to remove LSE from the Applicability Section and the three requirements.Further, there are two typos in R3: the “o” in “Generation owner” should be capitalized; and “Regional Reliability Organization” should be “Regional Entity”.
Response:		
Southern Company Transmission	No	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...”)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.”)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. In Requirement 3 however it is unclear whether Generator Owners are held responsible for generator protection systems, transmission protection systems or both. 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?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.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.
Response:		

Organization	Yes or No	Question 27 Comment
Arizona Public Service Company	Yes	
CECD	Yes	
Dominion	Yes	
Dynegy Inc.	Yes	
National Grid	Yes	
Oklahoma Muncipal Power Authority	Yes	
Santee Cooper	Yes	
Springfield Utility Board	Yes	
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	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.
Response:		
Indiana Municipal Power Agency	Yes	IMPA supports this change, but transmission protection system needs to be defined by a SDT in the near future.
Response:		
Florida Municipal Power Agency	Yes	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

Organization	Yes or No	Question 27 Comment
		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?
Response:		
Western Electricity Coordinating Council	Yes	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 phase "according to the Regional Entity's procedures."
Response:		

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)?

Summary Consideration:

Organization	Yes or No	Question 28 Comment
Central Lincoln		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
IRC Standards Review Committee		
SDG&E		
United Illuminating Company		
Ameren	No	
American Electric Power	No	
CECD	No	
Consumers Energy Company	No	
Entergy Services	No	
ERCOT ISO	No	

Organization	Yes or No	Question 28 Comment
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	
Dominion	Yes	
Dynegy 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	Yes	

Organization	Yes or No	Question 28 Comment
Collaborators		
NERC Standards Review Subcommittee	Yes	
Oklahoma Muncipal 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)?

Summary Consideration:

Organization	Yes or No	Question 29 Comment
Central Lincoln		
Disturbance and Sabotage Reporting Drafting Team		
SDG&E		
IRC Standards Review Committee		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.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.
Response:		
central Maine Power Company		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.
Response:		
National Grid	No	
Xcel Energy	No	

Organization	Yes or No	Question 29 Comment
Springfield Utility Board	No	"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 reliabilty.The language referring to controllable load and laod 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"
Response:		
Ameren	No	(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?
Response:		
United Illuminating Company	No	: 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.
Response:		
Georgia System Operations Corporation	No	29) We disagree with the inclusion of load shedding as a resource in VAR-001 R2, R5, and R9. Controllable load is certainly a 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).
Response:		
CECD	No	CECD is concerned with the impact to the BA if load shedding is used as a reactive resource and feels that

Organization	Yes or No	Question 29 Comment
		the standard must be modified to require the TOP notify the BA if load shedding is applied in this manner.
Response:		
Consumers Energy Company	No	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.
Response:		
IESO	No	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 that is responsible for identify this requirement.
Response:		
E.ON U.S.	No	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
Response:		
Northeast Power Coordinating Council	No	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

Organization	Yes or No	Question 29 Comment
		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.
Response:		
Southern Company Transmission	No	Paragraph 1858 - However, this is a tariff issue and unrelated to reliability.Paragraph 1879 - In R9, shedding load following the first contingency would seem to violate TPL-002, Category B events.
Response:		
Santee Cooper	No	Paragraph 1858 - Requirement 5 should be removed completely as we consider this to be tariff related and not reliability related. 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.
Response:		
Entergy Services	No	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.
Response:		
SERC OC Standards Review Group	No	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.

Organization	Yes or No	Question 29 Comment
Response:		
ERCOT ISO	No	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.
Response:		
Midwest ISO Standards Collaborators	No	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. While changes to R2, R5, R8 and R9 may address the Commission directives in paragraph 1879, we do not agree with the 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. 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.
Response:		
Arizona Public Service Company	Yes	
Dynegy Inc.	Yes	
Florida Municipal Power Agency	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	

Organization	Yes or No	Question 29 Comment
NERC Standards Review Subcommittee	Yes	
Oklahoma Muncipal Power Authority	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
US Bureau of Reclamation	Yes	
Western Electricity Coordinating Council	Yes	
American Electric Power	Yes	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.
Response:		
Kansas City Power & Light	Yes	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 Transmission Operator or Transmission Service Provider.
Response:		
Dominion	Yes	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

Organization	Yes or No	Question 29 Comment
		and reactive resource switching; controllable load; and, if necessary, load shedding -“. This makes the standard resource neutral, which is apparently the aim of FERC.
Response:		

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:

Organization	Yes or No	Question 30 Comment
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
ERCOT ISO		
Xcel Energy	No	
IESO	No	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.
Response:		
IRC Standards Review Committee	No	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

Organization	Yes or No	Question 30 Comment
		expediting non-impactive requirements or of addressing complex issues helps neither the Industry (who must expend resources on this SAR) nor NERC nor FERC.
Response:		
National Grid	No	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

Organization	Yes or No	Question 30 Comment
		“unsubstantial changes” (which are, in fact, substantial).
Response:		
Northeast Power Coordinating Council	No	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).

Organization	Yes or No	Question 30 Comment
Response:		
Midwest ISO Standards Collaborators	No	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 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.
Response:		
United Illuminating Company	No	The directives in Order 693 should be addresses 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 develop to prioritze and address the development of new and revised Standards.
Response:		
US Bureau of Reclamation	No	The process to modify these standards is not following the accept andapproved process. The excuse that

Organization	Yes or No	Question 30 Comment
		"FERC has expressed concern that industryand NERC have been less responsive than desired in providing a timelyresolution to those directives." offers no urgent or compelling reason for thisextraordinary step. It is suggested that NERC utilize the conventional standardmodification process for the changes requested by FERC.
Response:		
Ameren	No	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.
Response:		
American Electric Power	No	This is a redundant project, and effort should rather be spent in completing the existing project.
Response:		
Southern Company Transmission	No	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.
Response:		
Arizona Public Service Company	Yes	
Central Lincoln	Yes	
Consumers Energy Company	Yes	
Dominion	Yes	
Dynegy Inc.	Yes	

Organization	Yes or No	Question 30 Comment
Entergy Services	Yes	
Illinois Municipal Electric Agency	Yes	
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 Muncipal Power Authority	Yes	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.
Response:		
CECD	Yes	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.
Response:		
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 concerns of many that several standards needing full review have been only slightly modified to meet the directives.

Organization	Yes or No	Question 30 Comment
Response:		
Springfield Utility Board	Yes	SUB agrees with the intent and is strongly supportive of this process.
Response:		
NERC Standards Review Subcommittee	Yes	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.
Response:		
Florida Municipal Power Agency	Yes	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 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.

Organization	Yes or No	Question 30 Comment
Response:		
E.ON U.S.	Yes	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.
Response:		
Western Electricity Coordinating Council	Yes	While this same effort could have occured several years ago, I believe that NERC was trying to prioritize modifications based on impact to the BES. I beleive the priorities were for the mose part accurate and I commend NERC for their ongoing effort.
Response:		

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:

Organization	Yes or No	Question 31 Comment
CECD		
central Maine Power Company		
Disturbance and Sabotage Reporting Drafting Team		
E.ON U.S.		
ERCOT ISO		
IRC Standards Review Committee		
Xcel Energy		
Ameren	No	
Arizona Public Service Company	No	
Consumers Energy Company	No	
Dominion	No	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.

Organization	Yes or No	Question 31 Comment
Response:		
Dynegy Inc.	No	
Entergy Services	No	
Florida Municipal Power Agency	No	
Georgia System Operations Corporation	No	None.
IESO	No	
Illinois Municipal Electric Agency	No	
Kansas City Power & Light	No	
NERC Standards Review Subcommittee	No	
Oklahoma Muncipal Power Authority	No	
PacifiCorp	No	
Pepco Holdings, Inc. - Affiliates	No	
Santee Cooper	No	
SDG&E	No	
SERC OC Standards Review Group	No	

Organization	Yes or No	Question 31 Comment
United Illuminating Company	No	
Western Electricity Coordinating Council	No	
American Electric Power	Yes	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.
Response:		
Central Lincoln	Yes	
Indiana Municipal Power Agency	Yes	EOP-003 is currently in a draft phase under the UFLS project commenting and balloting phase.
Response:		
Springfield Utility Board	Yes	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, consisitency. However, with some changes the proposed standards could remove those conflicts.
Response:		
US Bureau of Reclamation	Yes	The process for modifying the standards was in accordance with the Standard Development Process.
Response:		
Midwest ISO Standards Collaborators	Yes	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.
Response:		

Organization	Yes or No	Question 31 Comment
National Grid	Yes	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.
Response:		
Northeast Power Coordinating Council	Yes	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.
Response:		
Southern Company Transmission	Yes	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.
Response:		

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:

Organization	Yes or No	Question 32 Comment
American Electric Power		
Arizona Public Service Company		
CECD		
Central Lincoln		
central Maine Power Company		
Dynegy Inc.		
ERCOT ISO		
NERC Standards Review Subcommittee		
Oklahoma Municipal Power Authority		
PacifiCorp		
Pepco Holdings, Inc. - Affiliates		
Santee Cooper		

Organization	Yes or No	Question 32 Comment
United Illuminating Company		
US Bureau of Reclamation		
Xcel Energy		
Western Electricity Coordinating Council		I still believe that the fill-in-the-blank standards need to be addressed to remove uncertainty in the application of these standards.
Response:		
Southern Company Transmission		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.
Response:		
IESO		None
Springfield Utility Board		SUB appreciates the work put into this process.
Response:		
IRC Standards Review Committee		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.
Response:		
Dominion		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

Organization	Yes or No	Question 32 Comment
		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.
Response:		
SERC OC Standards Review Group		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.
Response:		
Consumers Energy Company	No	
Florida Municipal Power Agency	No	
Kansas City Power & Light	No	
SDG&E	Yes	[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.[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.....
Response:		
Illinois Municipal Electric Agency	Yes	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

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		needs to be established until existing standards have gone through the results-based review.
Response:		
Midwest ISO Standards Collaborators	Yes	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.
Response:		
Indiana Municipal Power Agency	Yes	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.
Response:		
Ameren	Yes	Since it is widely acknowledged that sub requiremnts are really sub-parts of the main requirement and not each individual requirement, the sub-requiremnts should be removed as part of these effort. The reason for our comment is supported by the new Reliability Standrad Template available on the NERC site.
Response:		
Disturbance and Sabotage Reporting Drafting Team	Yes	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 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 friut”. 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.
Response:		

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Georgia System Operations Corporation	Yes	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.
Response:		
E.ON U.S.	Yes	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.
Response:		
National Grid	Yes	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.
Response:		
Northeast Power Coordinating Council	Yes	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.
Response:		
Entergy Services	Yes	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

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		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.
Response:		