NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Monitoring

The Project 2013-03 Drafting Team thanks all commenters who submitted comments on the draft stage 1 Standard (EOP-010-1) and Standard Authorization Request (SAR) addressing stages 1 and 2. Project 2013-03 will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in FERC Order No. 779:

1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures with predetermined and actionable steps to take prior to and during GMD events which take into account entity-specific factors that can impact the severity of GMD events in the local area.

2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. The Stage 2 standard(s) must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts. If the assessments identify potential impacts from benchmark GMD events, the standard(s) will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

The standard and SAR were posted for a 45-day formal comment period from June 27, 2013 through August 12, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 85 sets of responses, including comments from over 225 different people from approximately 140 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

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

Summary Consideration:

The drafting team has revised the standard to incorporate a number of stakeholder recommendations that the drafting team believes are appropriate to improve the standard. **As a result of comments received, the drafting team has identified the need to make significant changes to the standard. Although Section 4.12 of the NERC Standard Processes Manual indicates that the drafting team is not required to respond in writing to comments from the previous posting when it has identified the**

need to make significant changes to the standard, the drafting team is providing summary responses to the comments received in order to facilitate stakeholder understanding.

A summary response follows each question. Please note that because common issues were grouped together in the summaries, an individual's comment may have been addressed in the summary for a question that is different from the question in which they submitted the comment; the drafting team encourages reviewers to read all summary responses.

The drafting team made the following changes after reviewing stakeholder comments:

- A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in their Reliability Coordinator Area. IRO-005-3.1a Requirement R3 currently provides this obligation. However, the NERC Board has approved IRO-005-4 which would result in retirement of the requirement. The new Requirement R2 in EOP-010-1 will maintain the RC's responsibility for providing space weather forecast information. The implementation plan includes guidance for making the new Requirement R2 effective to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010-1 Requirement R2 are effective at the same time.
- In response to stakeholder comments that certain Requirements met Paragraph 81 criteria, administrative requirements for reviewing of GMD Operating Plans and Procedures within a 36-month period and for having a copy in the control room were removed.
- Several changes in language were made to improve the clarity of requirements and measures.
- Applicability:
    - Balancing Authorities (BA) have been removed from the applicable functional entities because there are no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The BA is not expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the Transmission Operator (TOP) and Reliability Coordinator (RC). Existing standards provide the required authority for action. A whitepaper with the drafting team's analysis is posted on the project page.
    - The applicable TOP has been clarified to include only those that operate power transformers with a high side wye-grounded winding with terminal voltage greater than 200 kV. This applicability statement describes the functional entity in terms of the assets that they operate, which could include non-BES assets. The applicability statement is not intended to define equipment to be protected by the Operating Procedures. The drafting team views 200 kV as the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. A whitepaper with the drafting team's analysis is posted on the project page.

Although some stakeholders suggested that Generator Operators (GOPs) be added to the standard as applicable entities, the drafting team maintains that a GOP's Operating Procedures specifically to mitigate the effects of GMD would need to be supported by an equipment-specific study and might require the use of GMD monitoring equipment. Because it is not reasonable to assume that all GOPs have such studies or monitoring equipment, GOPs have not been added to EOP-010-1. Consistent with Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03, and Generator Owners (GO) and GOPs will be considered for applicability with stage 2. A whitepaper with the drafting team's analysis supporting the applicability of EOP-010-1 is posted on the project page.

Some stakeholders also commented that the six-month implementation period was too short. The drafting team is sympathetic to the challenge of completing the necessary coordination in a six-month time period. However this implementation period was suggested in FERC Order No. 779 and the drafting team lacks strong justification for a specific longer period.

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, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
3.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
4.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
5.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
6.	Joseph DePoorter	Madision Gas and Electric	MRO	3, 4, 5, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Marie Knox	Midcontinent Independent System Operator	MRO	2
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6

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

11. Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
12. Scott Nickels	Rochester Public Utilities	MRO	4
13. Terry Harbour	MidAmerican EnergyCompany	MRO	1, 3, 5, 6
14. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
2.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Lowman	Duke Energy	SERC	1, 3, 5, 6
2. Tom Pruitt	Duke Energy	SERC	1, 3, 5, 6
3. Andrew Witmeier	Midwest ISO	SERC	2
4. Terry Bilke	Midwest ISO	SERC	2
5. Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
6. Scott Walker	TVA	SERC	1, 3, 5, 6
7. Steve Corbin	SERC	SERC	10
8. Jeff Harrison	AECI	SERC	1, 3, 5, 6
9. Danny Dees	MEAG Power	SERC	1, 3, 5
10. Mike Bryson	PJM	SERC	2
11. Ray Phillips	AMEA	SERC	4
12. Tim Hattaway	PowerSouth	SERC	1, 5
13. Jim Case	Entergy	SERC	1, 3, 6
14. Patrick McGovern	Georgia Transmission	SERC	1
15. Scott Brame	NCEMCS	SERC	1, 3, 4, 5
16. Chris Wagner	Santee Cooper	SERC	1, 3, 5, 6
17. Greg McKinney	EKPC	SERC	1, 3, 5
18. William Berry	OMU	SERC	3
19. Sammy Roberts	Duke Energy	SERC	1, 3, 5, 6
20. Ben Deutsch	SERC	SERC	10

				1	2	3	4	5	6	7	8	9	10
3.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Mark Godfrey	Pepco Holdings Inc	RFC	1, 3
2. Jane Verner	Pepco	RFC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Sasa Maljukan	Hydro One Networks Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1, 3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion	RFC	3, 5, 6
2.	Mike Garton	Dominion	NPCC	5, 6
3.	Randi Heise	Dominion	MRO	6
4.	Michael Crowley	Dominion	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL Energy Plus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

				1	2	3	4	5	6	7	8	9	10
7.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

				1	2	3	4	5	6	7	8	9	10
8.	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

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

2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Donald Weaver	New Brunswick System Operator	NPCC	2
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1
25.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
26.	Mark Kenny	Northeast Utilities	NPCC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6
5.	Gary Kobet		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	OG&E	SPP	1
2.	Don Hargrove	OG&E	SPP	3
3.	Leo Staples	OG&E	SPP	5
4.	Jerry Nottnagel	OG&E	SPP	6

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Terry Volkmann	Emprimus LLC and Volkmann Consulting								X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gale Nordling	Emprimus	NA - Not Applicable	NA
2.	Fred Faxvog	Emprimus	NA - Not Applicable	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	RBB Vote - Seg 1	RFC	1
2.	Cindy Stewart	RBB Vote - Seg 3	RFC	3
3.	Doug Hohlbaugh	RBB Vote - Seg 4	RFC	4
4.	Ken Dresner	RBB Vote - Seg 5	RFC	5
5.	Kevin Querry	RBB Vote - Seg 6	RFC	6
6.	John Reed	FE	RFC	1
7.	Chris Pilch	FE	RFC	1
8.	Mike Miller	FE	RFC	1
9.	Marissa McLean	FE	RFC	1
10.	Larry Raczkowski	FE	RFC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Denise Lietz	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Erin Apperson	Puget Sound Energy	WECC	3
2.	Lynda Kupfer	Puget Sound Energy	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
3.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
4.	John Shaver	Southwest Transmission Cooperative	WECC	1
5.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	Paul Jackson	Buckeye Power	RFC	3, 4
8.	Bill Hutchision	Southern Illinois Power Cooperative	SERC	1
9.	Caleb Muckala	Western Farmers Electric Cooperative	SPP	1, 5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Daniel Herring	NERC Training & Standards Development	RFC	4
2.	Kent Kujala	NERC Compliance	RFC	3
3.	Al Eizans	Merchant Operations	RFC	5
4.	Barbara Holland	SOC	RFC	

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Michelle Corley	Cleco Power	SPP	1, 3, 5
3.	Louis Guidry	Cleco Power	SPP	1, 3, 5
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
6.	Beverly Laios	American Electric Power	SPP	1, 3, 5
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	James Nail	City of Independence, MO	SPP	3

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

	Additional Member	Additional Organization	Region	Segment Selection
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
10.	Dennis Sauriol	American Electric Power	SPP	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ran Xu	Technical Operations	WECC	1
2.	Dan Goodrich	Technical Operations	WECC	1
3.	James Burns	Technical Operations	WECC	1
4.	Richard Becker	Substation Engineering	WECC	1
5.	Don Watkins	System Operations	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson	JEA	FRCC	1
2.	Garry Baker	JEA	FRCC	5
3.	John Babik	JEA	FRCC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rene Free	Santee Cooper	SERC	1, 3, 5, 6
2.	Chris Wagner	Santee Cooper	SERC	1, 3, 5, 6
3.	Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Group	Pablo Onate	El Paso Electric Company	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Gustavo Estrada	El Paso Electric Company	WECC 5										
2.	Tracy Van Slyke	El Paso Electric Company	WECC 3										
3.	Luis Rodriguez	El Paso Electric Company	WECC 6										
4.	Pablo Onate	El Paso Electric Company	WECC 1										
23.	Individual	Janet Smith, Regulatory Affairs Supervisor		X		X		X	X				
24.	Individual	Bob Steiger		X		X		X	X				
25.	Individual	Lloyd A. Linke		X									
26.	Individual	Steve Rueckert											X
27.	Individual	Wayne Johnson		X		X		X	X				
28.	Individual	Ryan Millard		X		X		X	X				
29.	Individual	Steve Lancaster		X		X	X			X	X	X	
30.	Individual	Erika Doot		X				X					
31.	Individual	Kaleb Brimhall		X		X		X	X				
32.	Individual	William R. Harris									X		
33.	Individual	Paul Rocha	CenterPoint Energy	X									
34.	Individual	John Falsey	Invenergy LLC					X					
35.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36.	Individual	John Bee	Exelon and its Affiliates	X		X		X					
37.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
38.	Individual	Joe O'Brien for Ed Mackowicz	NIPSCO	X		X		X	X				
39.	Individual	Steve Hill	Northern California Power Agency				X	X	X				
40.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
41.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
42.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
43.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
44.	Individual	Anthony Jablonski	ReliabilityFirst										X
45.	Individual	Martyn Turner	LCRA Transmission Services Corp	X									
46.	Individual	Michiko Sell	Public Utility District No. 2 of Grant County, WA	X		X	X	X				X	
47.	Individual	Ben Li	Ben Li Associates		X								
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
49.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
50.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
51.	Individual	Jack Stamper	Clark Public Utilities	X									
52.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X				
53.	Individual	Rich Salgo	NV Energy	X		X		X					
54.	Individual	Jen Fiegel	Oncor Electric Delivery Complany LLC	X									
55.	Individual	Oliver Burke	Entergy Services, Inc.	X									
56.	Individual	Dan Inman	Minnkota Power Cooperative, INC.	X		X		X					
57.	Individual	Terry Baker	PRPA	X		X		X					
58.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
59.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
60.	Individual	David Jendras	Ameren	X		X		X	X				
61.	Individual	Catherine Wesley	PJM Interconnection, L.L.C.		X								
62.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
63.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
64.	Individual	Wryan Feil	Northeast Utilities	X									
65.	Individual	Phil Anderson	Idaho Power Company	X									
66.	Individual	Patricia Metro	National Rural Electric Cooperative Association (NRECA)	X		X	X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
67.	Individual	Bill Fowler	City of Tallahassee			X							
68.	Individual	Scott Langston	City of Tallahassee					X					
69.	Individual	Karen Webb	City of Tallahassee - Electric Utility										
70.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X				
71.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
72.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
73.	Individual	Bryan Griess	Transmission Agency of Northern California	X									
74.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
75.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
76.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
77.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
78.	Individual	Rhonda Bryant	El Paso Electric Company	X		X	X	X					
79.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
80.	Individual	Laurie Williams	PNM Resources	X		X		X	X				
81.	Individual	Nathan Mitchell	American Public Power Association			X	X						
82.	Individual	Linda Jacobson-Quinn	Farmington Electric Utility System			X							
83.	Individual	Rick Terrill	Luminant Generation					X					
84.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
85.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				

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

Organization	Supporting Comments of "Entity Name"
Massachusetts Municipal Wholesale Electric Company	American Public Power Association (APPA)
Western Electricity Coordinating Council	Florida Municipal Power Agency
PRPA	Florida Power & Light
Beaches Energy Services	FMPA
Indiana Municipal Power Agency	IMPA supports the comments submitted by Frank Gaffney from Florida Municipal Power Agency.
US Army Corps of Engineers	MRO NSRF
Associated Electric Cooperative, Inc. - JRO00088	NRECASERC
Portland General Electric Co	PGE supports WECC's position regarding the standard as it relates to the implementation timeframes.
PPL NERC Registered Affiliates	SERC OC Review Group
Tennessee Valley Authority	SERC OC Review Group
South Carolina Electric and Gas	SERC OC Review Group

Organization	Supporting Comments of "Entity Name"
Clark Public Utilities	Snohomish County Public Utility District
Nebraska Public Power District	Southwest Power Pool (SPP)
PNM Resources	WECC Staff

1. **The SDT is proposing that the draft stage 1 Standard should apply to Reliability Coordinators, Balancing Authorities with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV, and Transmission Operator with a Transmission Operator Area that includes any transformer with high side terminal voltage greater than 200 kV. Do you agree that the SDT has correctly identified the applicable functional entities in the initial draft stage 1 Standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on the applicability section of EOP-010-1. All comments have been reviewed and the revised version of EOP-010-1 includes changes that the drafting team considers appropriate. The drafting team maintains that Generator Operators should not be an applicable entity in the Stage 1 standard and has removed the Balancing Authority from the applicability as well. All functional entities listed in the Reliability Functions section of the Standards Authorization Request may still be considered for applicability of Stage 2 standards. The drafting team has clarified that the applicable Transmission Operators are those with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV. The drafting team emphasizes that this applicability statement describes the functional entity in terms of the assets that they operate, and does not define equipment to be protected by the Operating Procedures. Additional technical details are available on the Project 2013-03 Project Page. A summary of comments and the drafting team's response is provided:

- **Applicability to Generator Operators. Commenters stated that that EOP-010-1 needed to include Generator Operators in order to require Generator Operators to develop procedures to protect or mitigate the effects of GMD on Generator Step-up transformers (GSUs).** To effectively assess the effects of GMD on a GSU and develop appropriate mitigating Operating Procedures, a Generator Owner and/or Generator Operator would require a GSU transformer study to determine the impact of Geomagnetically-induced Current (GIC) (GIC/thermal rating study) and equipment to monitor GIC at the high-voltage wye winding neutral. Requirements for studies and possible equipment for mitigation is beyond the scope for stage 1. Generator Owners and Generator Operators are appropriately included in the GMD Standards Authorization Request and will be considered for inclusion in Phase 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. The drafting team recognizes that some GO/GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure. Furthermore, The RC and TOP will be preparing a GMD Operating Plan and Operating Procedures respectively. Those procedures will address steps that each will be taking to address GMD impacts, which may include requiring one or more GOPs to take action. Existing standards provide obligations for the GOP to execute actions when requested by the TOP or RC (refer to TOP-001-2 and IRO-001-3), to prevent or mitigate identified emergencies. Additional technical justification for excluding GOPs and BAs from applicability in the stage 1 standard is provided in a supporting white paper posted on the project page.

- **Applicability to Balancing Authority. Commenters stated that the BA should be removed from applicability of the standard because the purpose and scope did not align with the BA functions in the NERC functional model.** The drafting team agrees with removing BAs from the applicability. BAs are responsible for the real time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the Transmission Operator (TOP) to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits. The BA would not be expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the TOP and RC. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and, at least, the concurrence of the TOP and/or RC. Additional technical justification for excluding GOPs and BAs from applicability in the stage 1 standard is provided in a supporting white paper posted on the project page.
- **Applicability to all networks greater than 200 kV with grounded-wye transformers. Commenters requested justification for this threshold, stated that the threshold was lower than necessary, or stated that the threshold was higher than should be allowed for reliability.** The drafting team has prepared a technical justification for establishing a 200 kV threshold in the applicability of EOP-010-1 and posted it to the project page. Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (for example 115 kV lines are typically less than 15 miles in average length), the resulting GIC generated by lines rated less than 200 kV are significantly less than those of higher voltages. Lines with voltage ratings less than 200 kV do not contribute a significant portion of GIC that result in half-cycle saturation of power transformers, and are typically ignored in system impact studies. Using a voltage higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap in many systems by excluding from the reliability standard a portion of the network that can be affected by GMD. Results of sensitivity analysis shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event. Therefore, establishing 200 kV as the lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature. Refer to the project page for a supporting white paper containing further analysis on this topic.
- **Relationship to the Bulk Electric System definition. Commenters wanted clarification about applicability to non-BES elements, or recommended language to specifically exclude non-BES elements.** The drafting team believes EOP-010-1 should apply to Reliability Coordinators and all Transmission Operators with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV. Regardless of BES definition, the >200 kV network can experience GMD impacts and needs to be included for the reliable operation of the Bulk-Power System as directed

in FERC Order No. 779. There is no requirement within EOP-010-1 for Transmission Operators to include or exclude specific transformers in their Operating Procedures.

- **Regional applicability. Commenters stated that entities in regions with lower risk or lacking historical evidence of GMD impacts should be excluded.** Stage 1 of FERC Order No. 779 is interpreted to apply to all regions. The proposed standard does not specify prescriptive measures and allows for each entity to consider entity-specific factors in developing their procedures or processes. Order No. 779 at P 29 directs NERC to "submit for approval one or more Reliability Standards that require *owners and operators of the Bulk-Power System* to develop and implement operational procedures to mitigate the effects of GMDs…" (emphasis added).

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) We recommend the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV.(2) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extremen GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southern most entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies. (3) Given the unsettled GMD science, we think it is premature to write a standard requiring specific GMD operating plans and procedures and may cause considerable overlap and redundancy within the standards which the P81 project was intended to remove and which FERC has already proposed to approve. For example, TOP-001-1a

Organization	Yes or No	Question 1 Comment
		R2 and R8 already requires the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Finally, EOP-001-2 R2.2 requires the TOP to “develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system”. These standards requirements are applicable at all times including during GMD events. Thus, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements. (4) The Balancing Authority (BA) should not be listed as an applicable entity in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. The background section is focused on preventing transformer hot spot heating and voltage collapse through excessive use of reactive power which clearly aligns with the TOP tasks and not the BA tasks in the NERC functional model. While the BA might have a role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support. The BA would commit generation in response to the TOP directions and would utilize existing operating procedures and processes it has for managing commitment of units. Its existing procedures and processes, for example, might include a minimum generation procedure. Implementing the procedure in response to excess generation that needs to be committed to respond to a GOP event would be no different than responding when load has simply decreased below the normal minimum generation limits. Thus, there is no need to add the BA because its existing procedures and processes would be sufficient to respond to the TOP actions.
Sacramento Municipal Utility District	No	~1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down transformers to distribution.~2. Referring to the Oak Ridge national Laboratory 319 report, the winding(s) in question needs to be wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with "wye" connected winding(s) above a certain

Organization	Yes or No	Question 1 Comment
		threshold voltage. Three phase core transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single core transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase core transformers.
Colorado Springs Utilities	No	o GOP should also be included. o Voltage level not a good indicator of susceptibility to ground induced currents. Possibly latitude, transmission line orientation or transmission line length a better indicator. If voltage were to be used, think higher voltage should be considered.
American Public Power Association	No	APPA appreciates the SDT's effort to limit the applicability of the proposed standard by setting a voltage threshold for TOPs and BAs. On the July 30th webinar the SDT stated that a technical whitepaper was being developed to justify the 200 kV threshold. APPA will hold any comments on the voltage threshold until after the whitepaper is released. We request that the whitepaper be provided soon so the industry has time to discuss this threshold prior to the final comment and ballot period.APPA recommends that the SDT modify the applicability section wording to replace "transformers" with "BES transformers." Including only BES transformers will make the applicability of the standard clear. Some Transmission Owners may have transformers with high side voltage above 200 kV, but they are connected radially so are not part of the BES. These transformers should be out of scope for this standard.
Minnkota Power Cooperative, INC.	No	Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV and smaller, high impedance non-BES transformers serving load. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems.Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV and a base rating of at least XX MVA". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers. The addition of "XX MVA" will limit the inclusion of small 200+ kV connected transformers. It is unclear as to what that limit should be and the evidence for that limit is unknown. Alternatively, could make the statement "includes BES power transformers with a high side terminal voltage greater than 200 kV" but this could exclude large load serving

Organization	Yes or No	Question 1 Comment
		transformers that do have a significant effect in relation to GMD events.
MRO NERC Standards Review Forum (NSRF)	No	Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potential transformers with high side terminal voltage greater than 200 kV. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems.Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers.
Florida Municipal Power Agency	No	FMPA appreciates the efforts of the SDT and, in general, we believe the standard is good. However, we believe the Applicability of the standard needs improvement; and that is the primary reason we are voting Negative.The ORNL report, which FMPA believes is already unreasonably pessimistic, made several conclusions that are not reflected in the applicability that FMPA believes ought to be:1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down trasformers to distribution.2. The winding(s) in question needs to be grounded wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with grounded wye connected winding(s) above a certain threshold voltage3. According the the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers.4. The primary concerns for GIC is for voltage collapse or relay misoperation due to increased MVAR demand of transformers that could potentially result in cascading, and potential damage to transformers (see SAR description of Industry Need); hence, the applicability should not be to BAs but only RCs and TOPs (see additional discussion in response to question 3).5. FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. Almost all 230 kV transformers are 3 phase / 3 leg core transformers with a much lower probability of becoming saturated; whereas, according to ORNL, about 15% of 345 kV transformers are single phase transformers

Organization	Yes or No	Question 1 Comment
		(Figure 1-19). In addition, the resistance ot 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line.FMPA assumes that GSU's owned by the GO and operated by the GOP is intended to be included in the applicability (since the vast majority of GSU's are grounded wye connected on the high side), but under the interconnecting TOP's operating plan. However, the applicability does not reflect this. If the intent of the SDT is to include these GSUs, then the applicability ought to be changed accordingly. As such, FMPA suggests the following for applicability:4.1. Functional Entities:4.1.1 Reliability Coordinator4.1.3 Transmission Operator with a:4.1.3.1 Transmission Operator Area that includes any BES transformer with three single phase transformers connected in a grounded wye configuration of 300 kV or greater; or4.1.3.2 Transmission Operator Area that includes any BES transformer with at least one grounded wye connected winding greater than 400 kV (either three single phase transformers or a three phase transformer); or4.1.3.3 Transmission Operator Area that interconnects with any generator interconnection facilities that include a GSU that meets either criteria 4.1.3.1 or 4.1.3.2
Idaho Power Company	No	For stage 1, operational procedures make sense for Transmission Operations and not necessarily for Generation Operations. However, generator step-up transformers (GSUs) with a grounded wye high side can be affected by geomagnetic induced current (GIC). If the GSU is the property of and/or controlled by a generator operator, transformer information such as GIC, temperature, dissolved gas and abnormal operation may not be easily monitored by the Transmission Operator. Any operational changes made by the Generator Operator will need to be coordinated by the Transmission Operator but the Transmission Operator may not be aware of GSU status. While System wide GMD operating procedures do not apply to Generator Operators, equipment level situational awareness and monitoring might. Idaho Power believes this standard should also apply to Generator Operators. Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities Section 4.

Organization	Yes or No	Question 1 Comment
PacifiCorp	No	Generator Operators are listed as applicable functions within the SAR but are absent from the scope of applicability of EOP-010-1. If Generator Operators are not included under the standard they should be removed from the scope of the SAR, as this creates inherent confusion as to their explicit applicability to the standard. Additionally, PacifiCorp does not support inclusion of the BA as an applicable functional entity.
Great River Energy	No	GRE agrees with ACES recommending the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV.GRE agrees with ACES and does not believe that the Balancing Authority (BA) should be listed as an applicable entity in the GMD standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. It would be the TOP or RC that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
Los Angeles Department of Water and Power	No	LADWP is making a correction to Question 1 and therefore is resubmitting its comments from yesterday. Please take these comments and regard the ones from yesterday.____Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One - Assess and Baseline RiskPhase Two - Perform Technical and Programmatic AnalysisPhase Three - Develop Integrated SolutionsPhase Four - Implement

Organization	Yes or No	Question 1 Comment
		Solutions and Adjust System ProceduresIt seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the "Geomagnetic Disturbance Operating Procedure Template" for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs.Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >20kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
National Rural Electric Cooperative Association (NRECA)	No	NRECA recommends increasing the voltage level threshold from 200 kV to 345 kV. The drafting team has not provided a technical justification for choosing the 200 kV threshold. It appears that from the limited previous experiences associated with GMD events that there was no substantive impact on equipment at voltages below 345 kV. In addition, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast. The inclusion of the Balancing Authority as an applicable entity is not necessary. If the events being addressed in this standard are solely related to preventing transformer hot spot heating and voltage collapse through excessive use of reactive power, these types of events are managed by the Transmission Operator not the Balancing Authority. The Balancing Authority will only provide generation support as directed by the Transmission Operator.
SPP Standards Review Group	No	Please refer to our comment in Question 7 directed toward applicability in the SAR.
Pepco Holdings Inc & Affiliates	No	Recommend adding "BES" as qualifier for transformer.4.1.1 Reliability Coordinator 4.1.2 Balancing Authority with a Balancing Authority Area that includes any BES transformer with high side terminal voltage greater than 200 kV 4.1.3 Transmission Operator with a Transmission

Organization	Yes or No	Question 1 Comment
		Operator Area that includes any BES transformer with high side terminal voltage greater than 200 kV
Los Angeles Department of Water and Power	No	Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One - Assess and Baseline RiskPhase Two - Perform Technical and Programmatic AnalysisPhase Three - Develop Integrated SolutionsPhase Four - Implement Solutions and Adjust System ProceduresIt seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the "Geomagnetic Disturbance Operating Procedure Template" for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs.Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >200kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
seattle city light	No	Seattle City Light supports the general concepts presented in the draft Standard and appreciates that the Standard Drafting Team affords each entity flexibility as to procedures. However, Seattle is concerned about the broad applicability of the Standard as proposed, and recommends that it only apply to BA and TOPs with Bulk Electric System (BES) transformers 200kV and above (as well as all RCs). This change would make this Standard consistent with other Standards as well as the BES definition we've worked so hard on the past several years.

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	No	See FMPA concerns on aplicability, type of transformer, and whether or not the BA should be an applicable entity.
Arizona Public Service Company	No	Should only apply to transformers which are part of BES. BES definition is based upon the low side winding voltage of greater than 100 kV where as this requirement is based upon high side voltage. Thus, this goes beyond BES elements. We suggest it apply to transformer with low side winding voltage of 200 kV or greater.
Public Utility District No.1 of Snohomish County	No	SNPD agrees in general but believes the 200 kV voltage threshold is premature. In general, we believe that GMD should be tackled on a regional basis and already by the Reliability Coordinator ("RC"). It is our understanding that location (latitude and local geology) and the type of systems (i.e., systems with extra-high-voltage, series capacitor compensated lines, transformer configuration & grounding, and line length) are important elements in a GMD analysis. Therefore, a one-size-fits-all approach based on voltage level would be inappropriate. SNPD believes the Reliability Coordinator ("RC") would be in the best position to identify facilities including the appropriate voltage level or other attributes that may become more apparent as research in this area matures.
Foundation for Resilient Societies	No	Standards relating to Operating Procedures should apply to high side Transformers of 100 kV or higher. Despite higher resistance, transformers in the 100 kV to 200 kV range contribute a significant proportion of GICs that can destabilize the grid. TJ Overbye et al (2012)estimate less than 60% of total MVAR is captured in New England and Michigan if transmission under 230 kV is excluded from protection. New transformers in the 100 kV to 200 kV range are projected by the Energy Information Administration at about 20% of all new EHV transmission mileage planned for the 2012-2018 period. NERC must include generating entities, because existing studies suffice to demonstrate both vulnerability of GSU transformers operated by Generating entities and need for equipment monitoring at generator stators, and related operating procedures to protect generators in severe geomagnetic storms. GSU Generators are at greater risk than generally recognized. See studies by Legro, Abi-Samra and Tesche at ORNL (1985); Walling &

Organization	Yes or No	Question 1 Comment
		Kahn (1991); J G Kappenman, Storm Analysis Report R-112, section 8 (2011); and Luis Marti, "Generator Thermal Stress during a Geomagnetic Disturbance" (2013). Of critical importance, the President of the United States has existing legal authority to order the de-energizing of electric generating facilities that are oil or gas-fired if an emergency so requires. To utilize this authority upon confirmed space warning of a severe solar geomagnetic storm, it is essential that all generating entities serving the bulk power system be included in emergency operating procedure standards; their personnel be trained to validate and confirm de-energizing orders and procedures (and re-energizing procedures), with a multi-day strategic warning but only tens of minutes for tactical order, validation, and execution. Because most of the generating facilities serving the bulk power system are not now equipped with protective equipment that would enable these facilities to "operate through" a severe solar geomagnetic storm, it is essential that generating entities be included in the Operating Procedure coverage and standards. Further, the Nuclear Regulatory Commission has existing authority to order de-energizing and safe shutdown of the 102 NRC licensed nuclear power plants in the U.S. or a subset that are especially affected by a particular GMD event. Generating entities may need to review operating procedure options for rapid shutdown of generators if GSU transformers are not equipped with protective hardware. Beyond the practical necessity of including transformers and transmission equipment in the 100 kV to 200 kV range, FERC Order 779 applies to the entire bulk power system, which is now defined as commencing at 100 kV or above and not 200 kV or above. It would be illegal for NERC to exclude a significant proportion of the transmission line mileage (for many utilities more than half total EHV transmission mileage). Even if EHV transformers above 200 kV are later protected with neutral ground blocking equipment, leakage of GICs from lower voltage equipment will add significant Mvar into regional grids. FERC intended standards to protect the entire bulk power system of 100 kV or higher; NERC's participating entities should respect and support this federal policy.
DTE Electric	No	System study of areas potentially affected by GMDs should be identified before standard is written requiring all entities to have plans and operating procedures.
JEA	No	The applicable entities should’t not include the BA but needs to include the GOs. Generator step up transformers are more critical to BES reliability than substation step down transformers. Only

Organization	Yes or No	Question 1 Comment
		BES transformers should be included.
Oncor Electric Delivery Complany LLC	No	The draft fails to include Generator Owners and Generator Operators that have step-up and auxillary transformers with a terminal higher that 200 kV. If GMD causes unintended ground induced currents (GICs) on Transmission Owners' and Transmission Operators Transmission Transformers that are important to the grid, then it stands to reason that step-up and auxillary transformers are at risk as well. Generator Owners transformers have a great impact to the reliability of the system. Those transformers need to be included in the Standard. Additionally, it would seem imperative to include generator owner transformers that supply offsite power to nuclear generation that are above 200 kV. The Standard must include the GO and GOP in order to address the FERC Order.
Puget Sound Energy	No	The drafting team should ensure that the voltage level in the applicability statement does not include elements excluded by the Bulk Electric System definition. Specifically, it appears that the applicability statement would include equipment excluded from the BES by the language of BES Definition Inclusion I1 ("Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher..."). Also, voltage level is not the only measure of GMD influence on the BES - there are other factors that the standard should include in its assessment of applicability, including grounding method, grounding resistivity, core type and transformer (coiled equipment) connections. Leaving these factors out of the applicability section means that many entities who are unlikely to be affected by a GMD event will be unnecessarily burdened with drafting procedures that they may never need. In addition, it is not clear why the Balancing Authority is included as an applicable entity - in general, the actions available to the operators are transmission system specific. However, if the Balancing Authority is removed as a responsible entity, the drafting team should ensure that generation interconnection facilities are also assessed for applicability with respect to the interconnected TOP.
NV Energy	No	The preparation and execution of operating procedures to mitigate the effects of GMD events on the power system are specific to the Reliability Coordinator and the Transmission Operator entities. We do not believe that actions are required of the Balancing Authority function at all, as this is not a balancing issue, but rather a transmission operations issue. Additionally, we

Organization	Yes or No	Question 1 Comment
		believe the scope of applicability should not reach into distribution transformers, particularly radial transformers serving distribution load. Hence, we recommend that the Applicability section be modified to remove 4.1.2 (Balancing Authority) and place a limitation on 4.1.3 to restrict applicability to BES transformers of the indicated voltage range.
LCRA Transmission Services Corp	No	The standard has not provided a clear reason for starting at 200 kV, which seems arbitrary. Papers on GMD do indicate the potential risk to transformer's increases at the higher voltage levels and in particular to single phase wye connected transformers. Would propose the following:4.1.3.1 a Transmission Operator Area that includes any BES transformer with three single phase core windings connected in a "wye" configuration of 300 kV or greater; or4.1.3.2 a Transmission Operator Area that includes any BES transformer with at least one "wye" connected winding greater than 400 kV;
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
Oklahoma Gas & Electric	No	This standard should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Tri-State Generation and	No	Tri-State believes that Balancing Authorities should not be included as an applicable entity because there will be unnecessary duplication or conflict between the BA and the Reliability

Organization	Yes or No	Question 1 Comment
Transmission Association, Inc.		Coordinator Operating Plans.
Texas Reliability Entity	No	We agree with the RC and TOP functions. The SDT may also want to consider adding the GOP function so that large GSU's are also monitored under this standard.
CenterPoint Energy	Yes	CenterPoint Energy agrees in general with the SDT proposal but has an alternative suggestion for the specific roles of the applicable responsible entities. Please see CenterPoint Energy's comments regarding Requirement 1 (Question 2).
City of Austin dba Austin Energy	Yes	During the July 30, 2013 GMD webinar, the response to one question was that the SDT would consider whether the BA applicability is appropriate. Austin Energy (AE) would encourage the SDT to complete that effort.
Northern California Power Agency	Yes	For Stage 1 I believe the SDT has it correct; however I am concerned that there is no mention as to what will happen with IRO-005-3.1a R3 which appplies to a host of registrations. At some point EOP-010-1 will supercede IRO-005-3.1a, but no mention in the implementation plan is discussed.
Emprimus LLC and Volkmann Consulting	Yes	For the Stage 1 standard, appropriate inclusion of affected transformers is not as important as it will be in Stage 2. What is important for the Stage 1 standard to capture in its applicability section the portion of the BES most effected by a GMD and the most influential to maintain BES reliability. In capturing RC, BA and TOP with 200kv transformers, the SDT has captured entities that have influence over the 200kv and above system. For entities the own and operate facilities between 100 and 200kv, their system reliability will be maintained by the RC and any neighboring / over-arching entities that operation 200kv and above.
Northeast Utilities	Yes	I agree with the applicability, however if the definition of BES changes I do not think this standard should apply down to those with transformers having high sides of 100 kV. The impact of GMDs and the magnitude of GICs is greatly reduced at these lower voltages and doesn't warrant the additional burden it would impose.

Organization	Yes or No	Question 1 Comment
PJM Interconnection, L.L.C.	Yes	PJM has also signed onto SERC's comments.
Santee Cooper	Yes	Recommend the SDT consider changing he high side terminal voltage on transformers to greater than 300 kV. The focus of the standard should be at higher voltages where the line length makes the lines more vulnerable to geomagnetically-induced currents.
Northeast Power Coordinating Council	Yes	The Applicability and Purpose conflict however. The Purpose says “To mitigate the effects of geomagnetic disturbances (GMD) events by implementing operating procedures.” But the Standard’s Purpose is not consistent with the Standard. The Standard goes into detail about the mitigation plans. Recommend the Purpose be “To establish and implement GMD mitigation operating procedures”. The effectiveness of these procedures to mitigate the effects of GMD is unknown.
Southern Company	Yes	The currently drafted standard does not include GOPs as an applicable entity. Consideration should be made to include them as an entity for reliability purposes. For example, a GOP may decide to take a unit offline if a K7 is declared, and if so, the reliability entities would need to know that these units are not available, if needed. In addition, if GOPs are added as applicable entities, they need to have a requirement to provide their plan to the reliability entities. Although we are suggesting adding the Generator Operator as an applicable entity, we do suggest that they be allowed to develop their own GMD Operating Plan or implement the GMD Operating Plan of its Transmission Operator.We also believe, consistent with our response to Question #7 below, that the standard should not apply to BAs, as the the risks mitigated by requiring them to have Operating Procedures are things that the TOP monitors and can either take action themselves or instruct the BA to redispatch generation.
ReliabilityFirst	Yes	There may be cases in which a transformer with a high side terminal voltage of greater than 200 kV is not considered BES (e.g., the transformer is excluded as part of a local network). ReliabilityFirst requests clarification whether this non-BES transformer is included within the

Organization	Yes or No	Question 1 Comment
		scope of the standard?
Salt River Project	Yes	We agree that the scope is appropriate.
Entergy Services, Inc.	Yes	We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. One of the reasons for the change is due to the number of transmission to distribution transformers where the high side voltage is 230 kV. On the other hand, having the 200 kV cutoff has the potential to create confusion for BA. A BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces.
Duke Energy	Yes	While Duke Energy agrees in principle with starting at 200kV and above for having a GMD process/procedure, we believe that 300kV and above would be a more appropriate bright-line. In addition, if the bright-line remains at 200kV and above, we recommend the SDT should consider an alternative method of including only 200kV and above BES elements. Lastly, Duke Energy believes that only transformers with wye connected winding(s) should be included because only wye connected winding(s) are affected by GIC(s).
SERC OC Review Group	Yes	Yes. We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. In addition, if the original language (greater than 200kV), remains in the standard, there should be an exception for equipment such as transformers.
Hydro One Networks Inc.	Yes	
Dominion	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Western Area Power Administration	Yes	
Bureau of Reclamation	Yes	
American Electric Power	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Ben Li Associates	Yes	

Organization	Yes or No	Question 1 Comment
Electric Reliability Council of Texas, Inc.	Yes	
Xcel Energy	Yes	
Farmington Electric Utility System	Yes	
Luminant Generation	Yes	

2. **In Requirement R1, the SDT is proposing to require Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan. This coordinating role for the RC is based on the functional model and addresses the Order No. 779 directive to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view. The defined term "Operating Plan" provides the RC with latitude to determine specific activities necessary to achieve this goal. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on Requirement R1. The drafting team reviewed all comments and has incorporated changes into a revised version of EOP-010-1. These changes include rewording part 1.2 and measure M1 to improve clarity. The drafting team believes the revised version of EOP-010-1 achieves the necessary level of coordination required for effective planning and real-time operations while at the same time preserving the Transmission Operator's latitude to act based on system specific or localized conditions. The drafting team has added a new Requirement R2 to the revised version of EOP-010-1 to maintain the Reliability Coordinator's responsibility for providing space weather forecast information and specified that this requirement would become effective upon retirement of IRO-005-3.1a Requirement R3. A summary of comments and the drafting team's response is provided:

- **Recommendation to replace the word "implement" with "coordinate" in Measure M1, and to clarify what is meant by 'Implement'. Commenters stated that the measure was not consistent with the requirement, and that the additional information was needed about the SDT's intent.** The SDT discussed this suggestion and agreed that the measure and requirement needed to be improved for consistency. The SDT agrees with the spirit of the comment, and Requirement R1 and corresponding Measure M1 have been revised to clarify what is intended by "implement". The SDT considers an operating plan, process, or procedure to be implemented by carrying out its stated actions. The measure now specifies that operator logs, voice recordings, or transcripts are the required evidence to show that the stated actions in an Operating Plan, Operating Process, or Operating Procedure have been carried out.
- **Recommendation to replace the word "all" with "applicable" in Requirement R1, Part 1.2. Commenters stated that the draft wording could cause confusion.** The SDT agrees with the spirit of the comment and deleted the word 'all'. The SDT believes that the applicability statement establishes to whom the requirement applies.

- **Recommendation to add Same Day Operations Time Horizon to Requirement R1. Commenters stated this addition would be appropriate.** Same-day Operations are described as routine actions required within the timeframe of a day, but not real-time. The SDT agrees with the commenter and has made a revision to the proposed standard.
- **Recommendation for a longer implementation period. Commenters stated that additional time was needed for coordination among applicable entities, or for additional studies or information.** The SDT is sympathetic to the challenge of completing the necessary coordination in a 6 month time period, but the 6 month implementation period was suggested in FERC Order No. 779. The intent of EOP-010-1 is to have applicable registered entities investigate the potential impacts to their system and equipment to the degree possible and establish reasonable operational steps to be taken to mitigate the impacts with the understanding that additional research is underway and will provide better information in the future. The SDT believes that some prudent steps can be taken in the absence of more complete information and that this standard is consistent with the directives in Order No. 779. The SDT anticipates that the process to achieve compliance with EOP-010-1 will require collaboration among the RC and all entities included in the RC's GMD Operating Plan.
- **Recommendation to modify the standard to require RCs to develop the Operating Procedures for entities in the Reliability Coordinator Area, which may be supplemented by optional procedures developed by TOPs. A commenter stated that in areas with a lower historical risk it is inefficient or ineffective for all TOPs to develop Operating Procedures. A commenter stated that when historical and physical evidence shows GIC conditions do not exist for a TOP then the RC should not be required to include them in their coordinating plans.** The SDT believes that the requirement to have Operating Procedures must apply to all applicable TOPs in each RCA. Response to GMD events will vary based on local conditions but a key feature to response is to ensure that all applicable entities are responding in a coordinated manner within the RC area. The RC's Operating Plan should provide the necessary level of coordination for efficiency and effectiveness. An RC's Operating Plan may include Operating Procedures, as defined in the NERC Glossary of Terms.
- **Comments that Requirement R1 lacks specificity. Some commenters stated that the RC was given too much latitude; some commenters stated that the RC should be required to establish trigger conditions and a means for verifying compliance within the RCA. Commentors stated that the wording in R1 and R3 is of a "fill-in-the-blank" nature.** The SDT believes that the variability in the impacts of GMD across the system, based on a number of factors, precludes the ability to develop prescriptive requirements for GMD response at the RC level. The term "fill-in-the blank" standards refers to standards that require a bulk power system user, owner, or operator to implement regional criteria that are not specifically part of a NERC Reliability Standard and is not applicable to EOP-010-1.
- **Recommendation to reword Requirement R1 so that the RC is responsible to "coordinate the development" of the GMD Operating Plan. Commenters viewed this as a more appropriate role.** The SDT has modified Requirement R1 to address this concern. The modifications and additional explanatory material are the SDT's attempt to clarify the dual obligations of the RC to both coordinate the development of the Operating Plan but also to implement the Operating Plan.

- **Clarification of the RC's responsibilities for space weather notifications.** The SDT agrees with commenters that supported requiring the RC to provide GMD forecast information. The drafting team noted that IRO-005-3.1a Requirement R3 currently provides this obligation. However, NERC Board has approved IRO-005-4 which, would result in retirement of that requirement. The SDT has added a new Requirement R2 to the draft standard to clearly designate the RC as the entity to disseminate space weather information to the applicable entities and specified the conditions in the implementation plan for making Requirement R2 effective upon retirement of IRO-005-3.1a Requirement R3.
- **Recommendation to use the defined term "Operating Process." Commenters provided several views including a recommendation to substitute Operating Process for Operating Plan in Requirement R1, and substitute "Operating Process" for "Operating Procedure" in R3.** The SDT believes that "Operating Plan" is the correct defined term with respect to the requirement assigned to the RC. However, the term "Operating Process" could apply to the requirement assigned to the TOP, so the SDT has modified R3 to include Operating Process.
- **Recommendation to require post-event analysis of GMD response.** The SDT agrees that this can be a valuable practice to assess the effectiveness of the plans and procedures. It does not believe that the practice should be required in the standard. There are processes at NERC to perform post-event analysis, apart from the standards process. The NERC Events Analysis program supports the industry's post-event review and learning needs, and this includes emerging risks. Additionally the GMD Task Force provides a forum for best practices and learning that can include post-event reporting and analysis from participating entities.
- **Market concerns during GMD events. A commenter stated that the standard should address suspension of the market during GMD events.** NERC Reliability Standards are market-neutral and neither mandate nor prohibit any specific market structure. Pursuant to Order No. 693, NERC Reliability Standards should have no undue negative effect on competition and should not limit use of the Bulk-Power System in an unduly preferential manner. NERC Reliability Standards do not preclude market solutions to achieving compliance with standards. See the Reliability and Market Interface Principles available here: http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.
- **Clarifications, rewording, and recommendations to enhance coordination. Commenters expressed concerns over the burden being required of RCs to coordinate Operating Procedures, the perceived limits of their authority to resolve conflicts, requirements to ensure coordination among RCs, and how to determine that coordination has occurred.** The SDT believes that the RC has sufficient authority to resolve coordination issues with applicable entities related to GMD Operating Plans, Processes and Procedures in the Reliability Coordinator Area. This authority is consistent with the NERC Functional Model, the NERC Rules of Procedure, and existing standards including IRO-001. Furthermore, the SDT believes that an effective Operating Plan cannot be created without the RC assuring coordination among all of the applicable entities in its RC area as well as coordination with its neighboring RC(s). The SDT has provided additional explanatory information in the draft to clarify what is intended by coordination. Coordination has occurred when the applicable entities, in conjunction with the RC, have reviewed and accepted the content of both the RC Operating Plan and the applicable entities' respective Operating Procedures. To improve clarity Part

1.2 of Requirement R1 was changed from "A process for the RC to determine that the GMD Operating Procedures are coordinated and compatible" to "A process for the Reliability Coordinator to review the GMD Operating Procedures". The SDT believes the requirement to ensure coordination between and among RCs is addressed in existing IRO standards. (Refer to IRO-014, Requirement R1). Therefore, the SDT has not added a duplicate requirement for coordination between and among RCs.

- **Comments on the need for vulnerability assessments. Commenters stated studies were needed to develop procedures.** The SDT believes the stage 1 standard meets the directives contained in FERC Order No. 779. The SDT recognizes that EOP-010 may be implemented without vulnerability assessments and specific action triggers based on system studies. The SDT believes that prudent steps to manage impacts of GMD on the power system can be undertaken, even in the absence of vulnerability assessments and equipment-specific action triggers. The SDT agrees that system studies will result in improved Operating Procedures, which may be part of an entity's mitigation strategy in stage 2 of the GMD reliability standards.

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	(1) R 1.1: This requirement needs clarification. It refers to a GMD Operating Plan requiring "a description of activities designed to mitigate the effects of GMD events....". It is not clear whether the "activities" are intended to be performed by the Reliability Coordinator or refer to the Operating Procedures of the Transmission Operators / Balancing Authorities, or some other type of activity directed by the Reliability Coordinator, but performed by other entities. FERC Order 779 only referred to a possible "coordination " of Operating Procedures and that element is captured separately in R 1.2. (2) R 1.2: The requirement for "compatibility" of Operating Procedures causes concern and should be deleted. FERC Order 779 (Par. 38) specified that GMD standards "should allow responsible entities to tailor their operational procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology and system topology. While FERC also directed NERC to consider the "coordination" of such operational procedures, it did not require the "compatibility" of such procedures. Manitoba Hydro already has in place operating procedures to respond to GMD events. The role of Manitoba Hydro's Reliability Coordinator is to notify Manitoba Hydro of GMD events and disseminate information on present and forecasted storm levels. This would be appropriately viewed as coordination. However, requiring a Reliability Coordinator to determine the "compatibility" of several entities' Operating Procedures goes beyond coordination and begs the question of what happens if there is a determination that certain Operating Procedures are not compatible. Does the

Organization	Yes or No	Question 2 Comment
		Reliability Coordinator have the authority to direct an entity to adopt a different procedure? If so, it is not clear how it would be determined which responsible entity must change its procedures. Most importantly, this requirement erodes the discretion that was granted to Transmission Operators and Balancing Authorities under Order 779.
ACES Standards Collaborators	No	(1) Having another duplicative “operating plan” does not improve reliability on the bulk electric system. The reliability standards already require several types of plans that could be enhanced to address GMD events. While we agree that flexibility is better than specificity, we disagree with the approach that another plan is required. The drafting team should consider enhancing existing operating plans and other approaches to respond to the FERC directive.(2) We believe that NERC should respond to the FERC directive with an equally efficient and effective alternative to developing a new reliability standard. Since the new standard will be largely redundant with with existing standards requirements, there is technical justification to support an alternate approach. The alternate approach would include relying on existing standards requirements. For example, IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective.(3) A reliability standard is not always the best solution to address a reliability concern. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. We cannot support a standard that attempts to address the issue in broad generalities. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
JEA	No	A vulnerability study is required before good operating procedures can be developed
American Public Power	No	APPA suggests that the word “all” in Requirement R1.2, be replaced with the word “applicable.” APPA believes using the word “all” in this context will bring into applicability TOs and BAs that

Organization	Yes or No	Question 2 Comment
Association		have transformers below the 200 kV threshold. Replacing “all” with “applicable” will limit confusion and avoid conflict with the applicability section of the standard.APPA is also concerned with the words “coordinated and compatible” in R1.2. On the July 30th webinar the SDT stated that a full scale power flow analysis would be the ideal way for the RC to determine compatibility of various plans. APPA is concerned with the cost to TOs and BAs of meeting this “ideal” therefore we suggest that the SDT give guidance on acceptable alternatives.
Florida Municipal Power Agency	No	Bullet 1.2 puts RC’s in a position of responsibility without authority, or at least implies such. The bullet requires the RC to “determine” that the plans of the BAs and TOPs are coordinated. What happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? FMPA suggests looking at the EOP-006 and EOP-005 construct for guidance.And as stated in response to question 1, the BA should not be an applicable entity.
Minnkota Power Cooperative, INC.	No	Comment #1) Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.Comment #2) Suggest replacing the word “all” in R1.2 to “applicable”.Rationale: Using the word “all” could be interpreted such that TO’s and BA’s that have transformers below 200kV could be affected. Replacing “all” with “applicable” would avoid confusion, and be in alignment with the SDT intent.
Los Angeles Department of	No	Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled

Organization	Yes or No	Question 2 Comment
Water and Power		separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events.Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
Los Angeles Department of Water and Power	No	Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events.Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
Great River Energy	No	GRE agrees with the MRO NSRF on the suggested language change in M1 for clarity and also to replace "implemented" with "coordinated". M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an "event driven" measure but the Requirement is to "coordinate" GMD Operating Plans. By using "coordinate" (versus implement) within the Measure, the measure uses the same words as the Requirement.This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability

Organization	Yes or No	Question 2 Comment
		in particular locations. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
Northern California Power Agency	No	I think there is too much latitude given. The guidance document describes GMD as more a global issue; not just a regional issue. I believe the guidance document provides a good list of activities for an RC to start with, but that these activities should be consistent between various RCs as well as the process the RCs will use to determimne if the TOP and BAs are coordinated and compatible.
DTE Electric	No	Instead of each RC, TO and BA developing its own plan to mitigate effects of GMDs, the standard should state that each TO and BA have a plan to support its RC's GMD plan. If individually created, the plans may conflict.
PacifiCorp	No	PacifiCorp supports Florida Municipal Power Agency's position as it relates to Question 2. R1.2 requires the RC to "determine" that the plans of the BAs and TOPs are coordinated but it is not clear what happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? PacifiCorp supports FMPA's suggestion to look at the EOP-006 and EOP-005 construct for guidance.
American Electric Power	No	R1, 1.2We are concerned by requiring the RC to "coordinate" Operating Procedures, and determine their collective compatibility. Exactly what actions would demonstrate coordination, and how could compliance of it be proven or shown? The word "coordinate" is very subject to interpretation, and could be inconsistently applied in various audits.R1.2 states that the GMD Operating Plan shall include "A process for the RC to determine that the GMD Operating Procedures ... are coordinated and compatible." This could potentially result in different coordination requirements in different regions and consequently, prevent entities who are operating in multiple regions to use consistent procedures within an entity's service territory.
City of	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission

Organization	Yes or No	Question 2 Comment
Tallahassee - Electric Utility		Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOPs and BAs” with “applicable TOPs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
City of Tallahassee	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
City of Tallahassee	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Farmington Electric Utility System	No	Recommend rewording R1.2 “A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.” FEUS has concerns with how the RC would ensure ALL the TOP and BA plans are coordinated and compatible. In addition, FEUS is unclear what demonstrates a plan is compatible.
NV Energy	No	Requiring the RC to develop and maintain a plan is an appropriate requirement; however, it is unclear what the RC must do under 1.2 to "determine" that the GMD Operating Procedures in its area are coordinated and compatible. Suggest a language change to "A process for the RC to review and coordinate the GMD Operating Procedures of all TOP's in the RC Area."
MRO NERC Standards Review Forum (NSRF)	No	Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate

Organization	Yes or No	Question 2 Comment
		that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.
Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) and Western Area Power Administration (WAPA) recommend that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
Oncor Electric Delivery Complany LLC	No	The proposed language of R1 assumes all Regions operate the same therefore in order to support the structure of Regions across the North American utility industry, Oncor recommends R1 be revisedto:”Each Reliability Coordinator shall coordinate the development and maintain a GMD Operating Plan with its Balancing Authority, Transmission Owners, Transmission Operators, Generator Owners, and Generator Operators that coordinate GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:” Oncor believes the RC should remain responsible for implementing the plan.
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to

Organization	Yes or No	Question 2 Comment
		determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
Puget Sound Energy	No	This requirement imposes a heavy burden on the RC. Understanding that some level of coordination is required, perhaps a lesser level of coordination will be acceptable, at least until phase 2 of the project is complete. Such coordination could be modeled after the approach in IRO-010, where the RC would set the specifications for the TOP Operating Plans and the TOP would be required to comply with those specifications.
Texas Reliability Entity	No	This wording in R1 and R3 are “fill-in-the-blank” type of requirements that NERC has been trying to move away from. We understand that Phase 2 of the GMD Standard project will provide additional details and clarification.
Tri-State Generation and Transmission Association, Inc.	No	Tri-State believes that the proposed standard, as written, is too vague and gives the Reliability Coordinator too much latitude to create plans as only it deems appropriate. It also does not provide for industry review of these plans beforehand. Requirement R1 appears to be a "fill in the blank" requirement, which FERC does not approve.
Emprimus LLC and Volkmann Consulting	No	We agree with the language of develop, maintain and implement a GMD Operating Plan. However, the requirement does not have any evaluation of whether the Operating Plan was appropriately and effectively implemented for an event. M1 should include a post-event evaluation activity and subsequent documentation of the plan implementation.
Salt River Project	No	We believe that the requirement should state that the Reliability Coordinator should establish triggers that are appropriate for the given geographical and system exposure for each TO or BA. We would suggest language such as the following:R1.1 The Reliability Coordinator shall create a preliminary assessment of the exposure for each BA and TO. The plan and procedures developed by the Reliability Coordinator shall establish trigger levels for initiating and terminating these

Organization	Yes or No	Question 2 Comment
		plans or procedures based on the preliminary assessment of exposure for each BA or TO.
Duke Energy	Yes	Duke Energy believes R1.2 should be changed to "Each Reliability Coordinator shall have an Operating Process to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities in the Reliability Coordinator Area are coordinated and compatible."
Public Utility District No.1 of Snohomish County	Yes	Appropriate implementation time should be given so that the RC has time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions. Although GMD and Geomagnetically Induced Currents ("GIC") have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufactures. Recent work presented at the 2013 IEEE PES General meeting by Emanuel Bernabeu, Dominion "Overview of GMD Phenomena and ways to study the impact on the transmission system" and Ramsis Girgis, ABB "Equipment issues transformers, (Major Concern)'s etc. -from the transformers committee, impacts on transformer fleet and new designs" will provide more insight into appropriate actions to be taken by the RC and impacted functions. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on how GMD can impact the BES and what level of risk does GMD pose compared to other adverse impact events. See IEEE Power & Energy article "Geomagnetic Disturbances" by IEEE Power and Energy Society Technical Council Task Force on Geomagnetic Disturbances, July/August 2013 pg. 71-78.
Bonneville Power Administration	Yes	BPA's position is that the primary entities responding to GMD events are the TOPs and BAs. BPA believes the RC should be required to develop the criterion for their Operating Plan in direct coordination with the TOPs and BAs in their area in order to avoid the RC developing a plan that may not be compatible with the region. Additionally, the RC should be the primary source of space/weather information and be required to disseminate that information to the TOPs and BAs in their area.
CenterPoint Energy	Yes	CenterPoint Energy agrees in general with proposed Requirement 1 but offers an alternative proposal on specific aspects of the Requirement. We propose that the SDT modify R1 to read as

Organization	Yes or No	Question 2 Comment
		follows: Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan consisting of Operating Procedures developed by the Reliability Coordinator and coordination of GMD Operating Procedures that may be developed by individual Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.Discussion: We believe it is not necessary, beneficial, or efficient for each and every applicable Transmission Operator and Balancing Authority to try to develop GMD-related Operating Procedures and for the Reliability Coordinator to then try to harmonize multiple individual Operating Procedures in a way that benefits the region as a whole. We believe the most efficient and beneficial approach is for the Reliability Coordinator to develop an Operating Plan for the region, but allow (not require) individual Transmission Operators and Balancing Authorities to supplement the Reliability Coordinator's Operating Plan with individual Transmission Operator or Balancing Authority Operating Procedures, as along as those individual Operating Procedures, if any, are coordinated by the Reliability Coordinator.As repeatedly and correctly noted in the FERC Order, GMD assessment and mitigation requires a wide-area view. We believe some, if not most, individual Transmission Operators and Balancing Authorities will not be in a good position to reasonably determine what GMD-related operating actions would benefit the reliable operation of the entire region. Indeed, for some individual Transmission Operators and Balancing Authorities, it is possible and we believe likely that no action by that individual party is necessary or beneficial for the reliability of the region as a whole. The Reliability Coordinator has the wide-area view and is in the best position to determine what Operating Procedures would benefit the region as a whole. However, we also recognize that some individual Transmission Operators or Balancing Authorities may have already developed and implemented Operating Procedures, or may do so in the future based on specific concerns or vulnerabilities identified at some future time. We believe that it is beneficial to allow (but not require) individual Transmission Operators and Balancing Authorities to develop individual Operating Procedures based upon that entity's detailed knowledge and assessment of its facilities, as long as provision is made for the Reliability Coordinator to coordinate such discretionary individual procedures that would supplement the regional procedures.If the SDT agrees with CenterPoint Energy's proposal, the language of R1.2 would probably need to be modified by changing "...GMD Operating Procedures of all Transmission Operators and Balancing Authorities..." to "...GMD Operating Procedures of any submitted Transmission Operators and Balancing Authorities...". Also, R3 would need to be

Organization	Yes or No	Question 2 Comment
		modified. R4 and R5 would be deleted. CenterPoint Energy will discuss proposed changes to R3 in response to the next question.
Northeast Utilities	Yes	I agree that the RC should coordinate the plans for the BAs and TOPs in its area. It might be beneficial that there be coordination at the RRO level so that RC plans are coordinated as well, since GMDs/ GICs do not recognize arbitrary system borders.
Xcel Energy	Yes	In general, we agree with R1 & R1.1. However, we feel that R1.2 should be modified. Instead, we recommend the requirement read something like this: [1.2 A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.]
SERC OC Review Group	Yes	Language should be added to ensure coordination between adjacent RCs.
Entergy Services, Inc.	Yes	Language should be added to ensure coordination between adjacent RCs.
PJM Interconnection, L.L.C.	Yes	PJM has also signed onto SERC's comments.
Western Electricity Coordinating Council	Yes	Requirement is acceptable, but implementaiton period is too short
Southern Company	Yes	The SDT should consider creating criteria for the RC to use to ensure plans are coordinated and compatible. For example, criteria were developed for RCs to use to approve TOP restoration plans in EOP-006-2, R5, which indicates that the “Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its

Organization	Yes or No	Question 2 Comment
		Reliability Coordinator Area." Similarly, the SDT or a committee designated by the SDT should create criteria for RCs to use to ensure plans are coordinated and compatible.
Western Area Power Administration	Yes	Western Area Power Administration (WAPA) and the Bureau of Reclamation (Reclamation) believe that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, "A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event."
SPP Standards Review Group	Yes	While we concur that R1 addresses the FERC directive, we have some reservations with the use of the word 'coordinated' in R1.2 especially along the lines of what specifically will be required by the responsible entities to show coordination. Hopefully, the Reliability Coordinator will provide those details in his processes. Additionally, we would encourage the NERC Operating Reliability Subcommittee to ensure consistency in the processes used by the Reliability Coordinators throughout NERC.
Pepco Holdings Inc & Affiliates	Yes	
Hydro One Networks Inc.	Yes	
Dominion	Yes	
seattle city light	Yes	

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	
Oklahoma Gas & Electric	Yes	
FirstEnergy	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
Foundation for Resilient Societies	Yes	
Exelon and its Affiliates	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
ReliabilityFirst	Yes	

Organization	Yes or No	Question 2 Comment
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Ben Li Associates	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Company	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Luminant Generation	Yes	

3. **In Requirement R3, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to develop, maintain, and implement GMD Operating Procedures. The draft Standard is intended to allow each entity to develop its own procedures based on entity-specific factors as directed in Order No. 779. Do you agree that the SDT has correctly addressed the stage 1 directives in Order No. 779? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on Requirement R3. All comments have been reviewed and the revised version of EOP-010-1 includes changes that the drafting team considers appropriate. Several changes such as the removal of BA applicability have been explained in preceding sections. The drafting team agrees that an "Operating Process" as defined in the NERC Glossary of Terms can satisfy the reliability objective of R3 and has modified the requirement so that it can be satisfied by either an Operating Procedure or an Operating Process. The drafting team modified part 3.1 which addresses space weather information in the Transmission Operator's GMD Operating Procedure or Operating Process. A summary of comments and the drafting team's response is provided below:

- **Avoid overlapping requirements for space weather information. Some commenters indicated that Requirement 3, Part 3.1 is unnecessary or could conflict with IRO-005-3.1a Requirement R3.** The drafting team believes that receiving space weather information is an essential component to GMD Operating Procedures or Processes. The drafting team changed the language in Part 3.1 from "steps or tasks for the acquisition and dissemination of space weather information" to "steps or tasks to receive space weather information". The change reinforces the RC's responsibility to provide information that is relevant to reliability, while recognizing that Transmission Operators may use several sources in addition to the RC's disseminated forecast information to obtain more detailed local or system-specific information.
- **A commenter suggested guidelines be developed by a technical committee.** The GMD Task Force, which reports to the Planning Committee, has developed technical resources including the 2012 GMD Report and the Operating Procedure templates, which are posted on the GMD Task Force page of the NERC website. Additional technical resources and operator training are included in the GMD Task Force project plan. EOP-010-1 is being developed in response to FERC directives.
- **Tailoring of operating procedures. A commenter requested that language be included in Requirement R3 to reflect that entities are allowed to consider various entity-specific factors in developing GMD Operating Processes or Procedures.** The drafting team agrees with the principle that an entity can consider entity-specific factors in developing its process and procedure. However the suggested language is not a measureable requirement for mandatory compliance and therefore this language has not been incorporated.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) The proposed standard is responsive to the FERC directive, but it fails to take into account existing reliability standards that overlap with the proposed draft, and creates duplicative requirements that could result in double jeopardy. For instance, TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Since the electric industry has always taken an "all hazards" approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. These policies and procedures would, therefore, be sufficient to respond to a GMD event without the need to make them specific to the GMD event or without the need to create a duplicative standard. The drafting team or a NERC technical committee, such as the Operating Committee, could draft a reliability guideline to provide additional detail of how to prepare for GMD events and make recommendations for utilities in areas susceptible to GMD events to include preparations in their planning processes.
National Rural Electric Cooperative Association (NRECA)	No	As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
Entergy Services, Inc.	No	As mentioned in Q1, a BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces and may need to develop, maintain, and implement GMD Operating Procedures. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
Florida Municipal Power Agency	No	As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority

Organization	Yes or No	Question 3 Comment
		within the standards to require that additional unit commitment or redispatch.
City of Austin dba Austin Energy	No	Austin Energy (AE) believes that staggered enforcement dates between R1 and R3 are necessary for TOPs and BAs to develop Operating Procedures “that are coordinated with [their] Reliability Coordinator’s GMD Operating Plan.” The current implementation plan establishes a single date for all requirements. During the webinar, AE suggested this and the response was that NERC anticipates that TOPs' Operating Procedures will be developed first so the timing is acceptable. Given the definitions of Operating Plan and Operating Procedures in the NERC Glossary, AE understands how an Operating Plan can be built based on a series of underlying Operating Procedures, but if that is the intended order of operation, R3 should not require that Operating Procedures be coordinated with the RC’s Operating Plan.
JEA	No	BA should be removed
Public Utility District No.1 of Snohomish County	No	Because GMD can be a wide area event the BA and TOP efforts should focus on coordinating operations and procedures with the RC. Also GMD is a High-Impact, Low-Frequency event so overall risk to the TOP or BA area should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
DTE Electric	No	Entities with no previous effects from GMDs should be exempted by their RX from developing a plan and entities with potential problems with GMDs should be required to develop plans to support their RC's plan and provide plan details to their RC.
Northern California Power Agency	No	In a perfect world this should already exist is folks are truely in compliance with IRO-005-3.1a R3. How are the RCs, TOPs and Bas curently complying with IRO-005-3a? This might provide some insight for the SDT.
NV Energy	No	OK, except "Balancing Authority" should be removed from R3.
PacifiCorp	No	PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 3. As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and

Organization	Yes or No	Question 3 Comment
		procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority to require that additional unit commitment or redispatch.
Salt River Project	No	Please see Comment for question 2. The requirements for the Reliability Coordinator should be the same for the Transmission Operator and Balancing Authority.
Foundation for Resilient Societies	No	Reason: Earlier comments on the Operating Procedure Templates submitted by the Foundation for Resilient Societies were ignored, and not addressed on their merits by the GMD Task Force management and by the NERC Planning Committee. See our previous comments at: https://resilientsocieties.org/images/Comments Operating Procedure Template NERC GMDTF Phase 2 Rev1.pdf.
Farmington Electric Utility System	No	Recommend revising 3.2. to the following, "The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator to mitigate the effects on the system from GMD events." FEUS agrees it is pertinent mitigating activities are coordinated; however, we believe this level or coordination should be in line with what is expected for coordination activities during a restoration.
Xcel Energy	No	Recommend revising R3.1. It isn't clear as to what periodicity that an entity should be collecting and disseminating this information. Also, it is unclear as to what would qualify as a source to meet this requirement (i.e. is any 'space weather' source acceptable?). Suggest removing this requirement and indicate in prior requirement (R1) that RCs have the responsibility of collecting and sharing space weather information with TOPs and BAs, and RCs must subscribe to an authoritative space weather source.
Arizona Public Service Company	No	Requirment 3.2 requires coordination with Reliability coordinator's plan. Thus, there should be a provision that this requirement is effective only 6 months after the Reliability coordinator's plan is available.
CenterPoint	No	See CenterPoint Energy's response to the previous question. In this question, the SDT states,

Organization	Yes or No	Question 3 Comment
Energy		"The draft Standard is intended to allow each entity to develop its own procedures...". There is a difference between allowing each entity to develop its own procedures and requiring each entity to do so. R3, as proposed, would do the latter. CenterPoint Energy's proposed changes to R1 would allow, but not require, an individual entity to develop its own procedures that would supplement required regional procedures developed by the Reliability Coordinator. If the SDT agrees with CenterPoint Energy's proposed change to R1, R3 would be modified to require Transmission Operators and Balancing Authorities to submit individual Operating Procedures, if any are developed, to the Reliability Coordinator so that the Reliability Coordinator could ensure coordination that would benefit the region as a whole.CenterPoint Energy also has specific concerns that R3.1 is unnecessary and unduly prescriptive. On page 24 of the FERC Order, FERC describes NERC's concern with reliance upon the most familiar means of characterizing space weather information, the "K-Index". On Page 30 of the Order, FERC acknowledged NERC's concern and took no position regarding overreliance on the K-Index to trigger operational procedures. R3.3 appropriately allows the responsible entity to choose and then document for compliance what the trigger mechanism would be, which could be space weather information or some other mechanism (GIC monitoring, for example). If an individual entity concurs with NERC's view that space weather information is an unreliable means of triggering Operating Procedures, then that entity should not be required to acquire and disseminate such information.Proposed language changes to implement CenterPoint Energy's suggestions are as follows:R3 Each Transmission Operator and Balancing Authority that chooses to develop, maintain, and implement Operating Procedures to supplement the Reliability Coordinator's Operating Plan described in R1 shall submit such supplemental Operating Procedures to the Reliability Coordinator for review and approval. 3.1 DELETED 3.2 DELETED (addressed by R1.1) 3.3 Moved to Requirement 1 as R1.3R4 DELETED (addressed by R2)R5 DELETED
Texas Reliability Entity	No	See comments for #2 above.
Seminole Electric	No	Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of various entity specific characteristics in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole

Organization	Yes or No	Question 3 Comment
		proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures:"An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures."Seminole believes that this is not clear in the Requirement and wishes that the NERC SDT specifically state the ability for an entity to tailor their plans and/or procedures to their environment. In addition, the suggested language is pulled from the SAR for this project.
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, the TOP should not be required to have plans specifically for GMD events.
Oklahoma Gas & Electric	No	This standard should not be applicable to the Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Western Area Power Administration	No	WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation believe it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch

Organization	Yes or No	Question 3 Comment
		or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address "The steps or tasks for receiving and disseminating space weather information to its System Operators."
Bureau of Reclamation	No	WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation suggest that it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2 respectively. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address "The steps or tasks for receiving and disseminating space weather information to its System Operators."
Emprimus LLC and Volkmann Consulting	No	We agree with the language stated in R3. However, R3 should include the requirement of the TOP to communicate that they have implemented their Operating Procedures. Likewise the requirement does not have any evaluation of whether the Operating Procedures were appropriately and effectively implemented for an event. M3 should include a post-event evaluation activity and subsequent documentation of the plan implementation
Los Angeles Department of Water and Power	No	While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could

Organization	Yes or No	Question 3 Comment
		lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Los Angeles Department of Water and Power	No	While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Sacramento Municipal Utility District	No	
Ben Li Associates	Yes	1. We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a. 2. It R3 is to be retained, then it does not mention "applicable" BAs and TOPs, which it should. Further, a BA or TOP should be able to adopt a template procedure developed by its Reliability Coordinator. This should be explained in an administrative appendix to the standard.

Organization	Yes or No	Question 3 Comment
Idaho Power Company	Yes	Agree in General. Propose adding Generator Operator to R3 and M3. The Reliability Coordinator needs to coordinate their procedures with the Transmission Operator, Balancing Authority and Generator Operator.
Southern Company	Yes	An additional requirement should be added requiring BA/TOPs to send their initial plans and any revisions to the RC for review, since the RC has responsibility for ensuring plans are coordinated and compatible.
Great River Energy	Yes	Because of the wide-area nature of a GMD event, GRE is suggesting a higher level authority such as the NERC Operating Committee or a NERC technical committee consider drafting guidelines to provide details in preparing for GMD events that would include recommendations to entites in areas susceptible to GMD events.
PJM Interconnection, L.L.C.	Yes	PJM has signed onto SERC's comments. PJM also signs onto the SRC's response to Question #3.
Exelon and its Affiliates	Yes	R3.3, font is incorrect - need the entire number to be bold.
Northeast Utilities	Yes	The language in R3 is adequate.
Tri-State Generation and Transmission Association, Inc.	Yes	Tri-State agrees that R3 properly addressed FERC Order No. 779, but believes the implementation periods should be modified. A 6 month implementation period requiring the Reliability Coordinator to develop the Operating Plan and the Transmission Operator/Balancing Authority to develop the Operating Procedures is not suitable. The Transmission Operator/Balancing Authority needs time to ensure their procedures are in accordance with the Reliability Coordinator's Operating Plan so the implementation dates need to be staggered.
Independent	Yes	We agree with the proposed requirement. However, there currently exists a similar requirement

Organization	Yes or No	Question 3 Comment
Electricity System Operator		in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and BalancingAuthorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist asneeded in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a.
Electric Reliability Council of Texas, Inc.	Yes	We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and BalancingAuthorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist asneeded in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedures in place and be required to monitor GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT propose retiring R3 of IRO-005-3.1a. If R3 is to be retained, then it does not mention “applicable” BAs and TOPs, which it should.
MRO NERC Standards Review Forum (NSRF)	Yes	
SERC OC Review Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Hydro One Networks Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Dominion	Yes	
seattle city light	Yes	
Northeast Power Coordinating Council	Yes	
FirstEnergy	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
Colorado Springs Utilities	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
The United Illuminating Company	Yes	
ReliabilityFirst	Yes	

Organization	Yes or No	Question 3 Comment
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Oncor Electric Delivery Complany LLC	Yes	
Minnkota Power Cooperative, INC.	Yes	
Duke Energy	Yes	
American Public Power Association	Yes	
Luminant Generation	Yes	

4. In Requirements R2 and R4 the SDT is proposing to require applicable entities to review their GMD Plans/Operating Procedures every 36-months. This periodicity would ensure improvements in the scientific understanding of GMDs can be incorporated into Operating Procedures in a timely manner as directed in Order No. 779. In Requirement R5, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms, which is consistent with other EOP reliability standards. Do you agree that the SDT has correctly addressed the directives in Order No. 779 in a manner that is good for reliability with these requirements? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The drafting team thanks all who commented on Question 4. The drafting team reviewed all comments and has incorporated changes into a revised version of EOP-010-1. The drafting team agrees that applicable entities will be required to review and update its GMD Operating Plans, Procedures, and/or Processes in order to meet the requirement to maintain them in Requirements R1 and R3. As a result, Requirements R2 and R4 from the initial draft of EOP-010-1 have been deleted in the revised version as administrative and duplicative, consistent with the Paragraph 81 criteria (submitted to FERC in Docket No. RM13-8-000). Additionally, Requirement R5 was determined to be unnecessary for reliability and deleted in the revision because Requirements R1 and R3 require that applicable entities implement their GMD Operating Plans, Procedures, and Processes. The drafting team believes that these revisions have produced a clear, high quality, technically sound and results-based standard.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	No	(1) Requirements R2, R4 and R5 meet one or more Paragraph 81 criteria and should not be written as separate requirements that will result in a separate violation for failing to conduct the review on a timely basis or failing to have a copy of the operating plan or procedure in the control centers. A requirement is subject to retirement under P81 if the requirement fits any of the following criteria: it is administrative in nature, requires data collection/data retention, purely documentation or reporting, requires periodic updates, concerns only a commercial or business practice, is redundant with other standards, hinders the protection or reliable operation of the BES, or has little, if any, value as a reliability requirement.(2) Requirement R5 is very

Organization	Yes or No	Question 4 Comment
		similar to CIP-003-3 R4 which requires the cyber security policy to be available to all personnel with access to or responsibility for Critical Cyber Assets. In the P81 NOPR, FERC recently proposed to approve retiring CIP-003-3 R4 because it is administrative and it would be not be practical to implement the cyber security policy if it was not available to personnel. Similarly, R5 would be redundant with R3 because R3 has an implementation requirement. How can the TOP or BA implement the operating procedure if it is not available to its operating personnel per R5? How would an auditor verifying that a copy of the plan in the primary and backup control rooms benefit reliability? It could be placed in these rooms with no notification to system operators and no training provided to system operators on the implementation. Obviously, this would not support reliability. Requirements R2 and R4 are similar to the NUC-001-2 R9.13 which compel the Nuclear Plant Generator Operator and Transmission Entity to review their agreement every three years. FERC also proposed to retire it. Thus, R2 and R4 should be removed. If some vestige R2 and R4 are to remain, they should be made a sub-part of R1 and R3 so that a separate violation is not recorded for failure to review in the 36 month time frame. (3) We do agree that the 36-month time frame for review is reasonable.
Dominion	No	As R2 and R4 are currently written, they are purely administrative and do nothing to improve or insure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.
Sacramento Municipal Utility District	No	Every 36 months is too short of a time-frame. It would be more appropriate to have a review of a potential plan, if indeed needed, when system configurations warrant a review. The review period should be set by the entity, IF there is even a concern.
Exelon and its Affiliates	No	Exelon believes that performing a review of GMD Plans / Operating Procedures every 36 months is contrary to the Paragraph 81 criteria whose effort was to remove truly administrative requirements that do not have an impact on electric grid reliability. We feel tha R2, M2 and R2, M4 should be removed.
NextEra Energy	No	NextEra Energy is pleased with the work the GMD SDT has done in a very quick period of time, with the exception of adding certain requirements that no longer fit within the paradigm under

Organization	Yes or No	Question 4 Comment
		which Standards are to be drafted. NextEra suspects that these requirements were added because of the short period of time in which the SDT drafted the Standard, and, thus, NextEra is hopeful that once highlighted here that the SDT will quickly decide to delete the requirements as they are inconsistent with current Standard drafting practices. These requirements are inconsistent with both results based and P81 concepts, given that they are administrative in nature and do little to promote reliability. While some may see these requirements as good practices, adding them is no longer consistent with Standard drafting practices nor desired by stakeholders. New Standards are to be clear, high quality, technically sound and results based. Also, these requirements are similar to those that FERC recently indicated it would approve for retirement in the P81 Notice of Proposed Rulemaking. Therefore, NextEra requests that these requirements, noted below, be deleted. R2. Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. R4. Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date.
PacifiCorp	No	PacifiCorp affirms that if the intent of a review of an entity's GMD plans and procedures is to improve the scientific understanding of GMDs, a more prudent requirement would be a periodicity that is post-operative event based.In the absence of a GMD event, the 36-month requirement is arbitrary and one that would likely be performed by an entity as a best business practice.
DTE Electric	No	Please see previous comments from Questions 1, 2, and 3.
Entergy Services, Inc.	No	R5 is an administrative requirement for which compliance may be unprovable. This requirement (to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms) is also redundant to PER-005, which requires a Job Task Analysis for every task performed by System Operators. All administrative requirements should be deleted.
Electric Reliability Council of Texas, Inc.	No	Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is

Organization	Yes or No	Question 4 Comment
		unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operatinbg personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.
Hydro One Networks Inc.	No	Requirement R5 is of a purely administrative nature, not contributing to reliability. Suggest to eliminate. Emphasis and focus should be in operating personnel training and awareness. If R5 is kept in the standard, request to clarify the meaning of "prior to its implementation date." We believe it should be "prior to actions to implement the plan." As written in could be misinterpreted as prior to the standard effective date.
Arizona Public Service Company	No	Requirement R5 is unnecessary and should be deleted altogether. This requirement is a process and not a standard and it is not necessary to have a hard copy when an electronic copy could be readily available. There is no reliability benefit to this requirement.
Pepco Holdings Inc & Affiliates	No	Requirement R5 seems administrative in nature (similar to other Paragraph 81 requirements) and seems duplicative of R3 which already requires implementation of the Operating Procedures (i.e. implementation could include making operation personnel aware of the Operating Procedure and having available). If a separate training requirement is developed, R5 would be further redundant. Recommend that R5 be removed.Requirement R2 and R4 require applicable entities to review their GMD Plans/Operating Procedures every 36-months. With solar cycles having an average duration of about 11 years and the Plan and Operating Procedure being potentially utilized 1-2 years during the peak years of the 11 year cycle, how was the 36 month review criteria reached? Recommend changing to a 48 month review period which still allows for 2-3 reviews during a 11 year solar cycle.
FirstEnergy	No	Requirements R2 & R4FirstEnergy questions the need for Requirement R2 and R4 which propose an every 3-year review of GMD operating procedures. This is an administrative task and should not be a reliability requirement subject to mandatory enforcement. The requirements do not adhere to principles identified by the Par. 81 team and now being applied across all drafting teams. Par 81 Criteria B1 Administrative which states "The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not

Organization	Yes or No	Question 4 Comment
		support reliability and is needlessly burdensome." Additionally, an upcoming draft revision to the NUC-001 standard is proposing to remove a similar obligation in NUC-001 (R9.1.3). FERC's Order 779 did not suggest a need for the responsible entities to periodically update their GMD Operating Procedures every 3-years. Rather in paragraph 39 the Commission states "While responsible entities will develop and implement operational procedures, NERC can support their efforts, for example, by identifying and sharing operational procedures found to be the most effective. NERC should also periodically survey the responsible entities' operational procedures, offer recommendations based on lessons-learned and new research findings, and re-evaluate whether modification to the Reliability Standards is warranted." It is our understanding that it's the ERO's responsibility to reconsider whether or not more specific minimum GMD procedure expectations should be codified in the standard at some future date. This could be done for example during the 5-year review period of the standard and the NERC GMD Task Force could be tasked with providing the review required of NERC and propose changes to the GMD standard if needed.Requirements R5Requirement R5 indicates a need for the Operating Procedures to be located at the primary and back-up control center facility. The intent of Requirement R5 is already covered in standard EOP-008-1, R2. FirstEnergy recommends that Requirement R5 be struck as a redundant obligation.
The United Illuminating Company	No	Requirements R2 and R4 t to review the plan is purely administrative. As the scientific knowledge evelves R1 and R3 requires a plan to be designed to mitigate the effects of GMD.
American Electric Power	No	Requirements R2 and R4 state that each applicable entity shall review its GMD Operating Plan/Procedures every 36 months from the last *effective* date while Requirement 5 states that the applicable entities shall have a copy of its GMD Operating Procedures in the control room(s) prior to its *implementation* date. AEP recommends referencing the effective date only.R5 should be changed to state "...shall have a hard or electronic copy of its GMD Operating Procedures..."
Northeast Power Coordinating	No	The review interval specified in R2 and R4 is 36 months. A five year review would be more appropriate given the length of the solar cycle.As R2 and R4 are currently written, they are purely

Organization	Yes or No	Question 4 Comment
Council		administrative and do nothing to improve or ensure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.Requirement R5 also is administrative, does not contribute to reliability, and can be eliminated. Suggest to eliminate the wording “All procedures should be at the primary and backup control center as part of normal business”. Emphasis and focus should be on operating personnel training and awareness.If it is decided to keep R5 in the Standard, request clarificiation of the meaning of “prior to its implementation date.” It should be “prior to actions to implement the plan.” As written it could be misinterpreted as prior to the Standard’s effective date.
SPP Standards Review Group	No	To address timing issues in R5, we suggest inserting the word ‘current’ between the ‘a’ and ‘copy’ and deleting the phrase ‘so that it is available to its operating personnel prior to its implementation date’. R1 would then readEach Transmission Operator shall have a current copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms. For consistency with EOP-005, we would suggest that the VRF for R5 be reduced to Low. This is an administrative requirement and does not merit a Medium VRF.Additionally, we wonder why the Reliability Coordinator is not required to have a copy of its GMD Operating Plan in its primary and backup control centers.
Great River Energy	No	With NERC’s Relaibilibity Assurance Initiative (RAI), the P81 initiative and the work performed by the Independent Expert Review Project, R2 & R4 are administrative in nature and suggest the drafting team remove these two requirements. Similarly, R5 is also in administrative and is redundant with R3 because R3 has an implementation requirement. Per the P81 NOPR, CIP-003-3, R4 which required the cyber security policy be available to all personnel with CCA responsibilities, has been approved to be retired.
Oklahoma Gas & Electric	Yes	We agree with the language of these three requirements, however, we believe that the Violation Risk Factor should be LOWER, not Medium for these documentation related requirements.
ReliabilityFirst	Yes	1)Requirement R2 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan” at the end of the requirement.

Organization	Yes or No	Question 4 Comment
		ReliabilityFirst suggests the following for the SDTs consideration: "Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date [of its GMD Operating Plan]."2) Requirement R4 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan.” ReliabilityFirst suggests the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date [of its GMD Operating Procedures]."
Idaho Power Company	Yes	Agree in General. Propose adding Generator Operator to R4, M4, R5 and M5. Many of the other standards are using a five year review cycle. The review requirement should also include a trigger based on system upgrades or major changes to system topology.
NV Energy	Yes	Agree with the 36 month cycle of review; however, BA should be removed from R4.
Florida Municipal Power Agency	Yes	Although FMPA agrees with a 3 year period, FMPA would prefer a requirement of once every 3 calendar years as opposed to 36 months to allow more flexibility in scheduling.Again, the BA should not be an applicable entity.
Los Angeles Department of Water and Power	Yes	Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Los Angeles Department of Water and Power	Yes	Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
PJM Interconnection, L.L.C.	Yes	PJM has signed onto SERC's comments.
Independent Electricity System	Yes	Requirements R2 and R4 could easily be combined. Is there a specific reason why the Reliability Coordinator is separated from the Transmittion Operator and the Balancing Authority? The

Organization	Yes or No	Question 4 Comment
Operator		wording in these two requirements is identical.
Northern California Power Agency	Yes	Yes, but I do not see that this is any different form complying with IRO-005-3 R3 except for the 36 month review cycle.
MRO NERC Standards Review Forum (NSRF)	Yes	
SERC OC Review Group	Yes	
seattle city light	Yes	
Emprimus LLC and Volkmann Consulting	Yes	
Bonneville Power Administration	Yes	
JEA	Yes	
Salt River Project	Yes	
Western Area Power Administration	Yes	
Western Electricity	Yes	

Organization	Yes or No	Question 4 Comment
Coordinating Council		
Southern Company	Yes	
Bureau of Reclamation	Yes	
Colorado Springs Utilities	Yes	
Foundation for Resilient Societies	Yes	
CenterPoint Energy	Yes	
NIPSCO	Yes	
American Transmission Company	Yes	
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County,	Yes	

Organization	Yes or No	Question 4 Comment
WA		
Ben Li Associates	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Public Utility District No.1 of Snohomish County	Yes	
Oncor Electric Delivery Complany LLC	Yes	
Minnkota Power Cooperative, INC.	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Duke Energy	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	
American Public Power Association	Yes	
Farmington Electric Utility System	Yes	
Luminant Generation	Yes	

5. **If you have any other comments on this draft Standard that you haven't already mentioned above, please provide them here.**

Summary Consideration: The drafting team thanks all who responded to Question 5. The drafting team reviewed all comments and has incorporated changes in response to suggestions from those comments into a revised version of EOP-010-1. A summary of comments and the drafting team's response is provided below:

- **One commenter suggested an appendix be included with the standard to support information sharing and learning.** The drafting team believes this activity should be addressed through existing mechanisms and not through additional requirements. The NERC Events Analysis program supports the industry's post-event review and learning needs, and this includes emerging risks. Additionally the GMD Task Force provides a forum for best practices and learning that can include post-event reporting and analysis from participating entities.
- **Commenters stressed the value of studies and analysis; some recommended that the ordering of stage 1 and stage 2 in the SAR and FERC Order should be reversed.** The drafting team agrees that detailed studies such as those that may be required in stage 2 will provide a better assessment of risk and more appropriate and effective mitigation measures. However, there are prudent measures to mitigate risk from a GMD event that can be implemented without detailed system impact studies. The drafting team believes EOP-010-1 provides a reliability benefit as written and meets the directives in FERC Order No. 779.
- **One commenter suggested changes to language used in the effective date section of the standard.** NERC Legal worked with a representative of the Canadian Electricity Association to revise the language to ensure it appropriately reflects the current mechanisms for making standards effective in each of the Canadian provinces.
- **Suggestions for an alternate approach to meeting the directives through existing standards**. **Some commenters disagreed with the drafting team's approach to meeting the stage 1 directives contained in FERC Order No. 779 with a new standard. Commenters argued for modifications to existing standards or a response to the FERC directive that points to existing requirements to avoid duplicating requirements.** The drafting team agrees that existing standards including IRO-014, EOP-001, and TOP-004 could be modified to meet the directives in the order. However, the drafting team recognized the challenges of developing and successfully balloting the stage 1 standards within the deadlines established by the order and chose to create a single new standard. We respect the view of some stakeholders that an alternate approach would have been preferred. The drafting team also agrees that existing requirements that are applicable at all times provide some mitigation during GMD events; however, this approach does not meet the directives in Order No. 779. The drafting team did not write prescriptive requirements for real-time actions to mitigate GMD events, which would duplicate TOP-001. Furthermore, planning and policy requirements contained in TOP-002, TOP-004, and EOP-001 do not meet the specific directives of FERC Order No. 779 as written.
- **A commenter supported the technical work but considered the posting of the draft standard for ballot simultaneously with the SAR to be a violation of NERC Rules of Procedure.** The scope of the current project was set forth in detail by the Federal

Energy Regulatory Commission in Order No. 779 and there is a January 2014 deadline associated with the project. The decision to simultaneous post the SAR and the proposed Reliability Standard with a ballot conducted during the last ten days of that comment period was approved by the NERC Standards Committee. We respect your disagreement with this process decision and hope that you will continue to participate in the development of this standard.

- **Comments provided about draft GMD Task Force Planning Application Guide were considered out of scope for Stage 1 standards. Specific comments on the GMD Task Force Operating Procedure template were reviewed and did not affect the development of EOP-010-1 requirements but are valid points to consider in developing an entity's Operating Procedures.**
- Several suggestions for changes to wording were provided, considered, and incorporated into revisions when the drafting team agreed that they provided an improvement. The drafting team did not agree with comments suggesting the removal of the Long-term Planning Time Horizon from Requirements R1 and R3 because the required action, which is the development of Operating Plans, Processes, or Procedures, could take place years before a space weather event necessitating carrying out the actions in an entity's Operating Process or Procedure.
- The drafting team does not intend to produce a separate Guidelines and Technical Basis section for EOP-010-1, but has posted technical resources on the project page. The GMD Task Force page also contains technical references and task force products including the 2012 GMD Report.
- **Several commenters stated that Requirement R5 is not needed.** As noted above in response to Question 4, Requirement R5 was determined to be unnecessary for reliability and deleted in the revision since Requirements R1 and R3 require that applicable entities implement their GMD Operating Plans, Procedures, and Processes.

Organization	Question 5 Comment
Oklahoma Gas & Electric	While we understand the good intentions of FERC in Order No. 779, we feel that industry's time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
Manitoba Hydro	(1) Background - for clarity, consider replacing the words "can lead to" with [may result in]. (2) Purpose - for clarity, consider replacing the purpose section of the standard with the following sentence: "To [ensure plans, operating procedures, and resources are maintained and available] to mitigate the effects of geomagnetic disturbance (GMD) [emergencies on the bulk electric system.]" (3) M2 - consider revising the measure as follows:"Each Reliability Coordinator shall have evidence [showing] that it has

Organization	Question 5 Comment
	reviewed its GMD Operating Plan within the timeframe of Requirement R2. [Acceptable evidence could] include a dated review signature sheet or revision history." (4) 3.1, 3.2 and 3.3 - for completeness, start the sentence with [A listing of the]. (5) M4 - consider revising the measure as follows: "Each Transmission Operator and Balancing Authority shall have evidence [showing] that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4. [Acceptable evidence could include] a dated review signature sheet or revision history." (6) Table of Compliance Elements, R2, Low, Medium, High VSL - insert the word [last] before the words "effective date" for consistency with Requirement R2. (7) Some entities may reduce exports to neighbors as a mitigating strategy. This method, determined to be the ideal action, based on system studies, may be perceived as potentially impacting neighbouring entities. What level of coordination would be required or appropriate to permit the curtailment of exports?
ACES Standards Collaborators	(1) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will be viewed as this coordination. (2) The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions". A operating plan contains operating procedures and processes. (3) Part 3.1 in R3 is unnecessary because NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. There is not a need to codify a process that is already in place and works

Organization	Question 5 Comment
	effectively.
Western Area Power Administration	: WAPA and Reclamation also believe Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
ReliabilityFirst	1) Requirement R5 - To be consistent with the language in the other requirements within the standard, ReliabilityFirst recommends changing the term “implementation date” to “effective date.” ReliabilityFirst offers the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its [effective] date." 2) Consideration for new Requirement R6 - ReliabilityFirst recommends including a new Requirement R6 which would require adjacent Reliability Coordinators to share their respective GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators should be aware of each other’s GMD Operating Plans. 3) VSL Requirement R2 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "...but less than or equal to..." language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than [or equal to] 39 months, since the effective date."4) VSL Requirement R4 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "...but less than or equal to..." language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than [or equal to] 39 months, since the last effective date."
Tri-State Generation and Transmission Association, Inc.	1. Tri-State believes a 6 month implementation period isn't appropriate for this. This implementation period requires the RC to develop the Operating Plan and the TOP/BA to develop the Operating Procedures at the same time. The TOP/BA needs time to ensure their procedures are in line with the RC's Operating Plan so the implementation dates need to be staggered. 2. Tri-State also believes Stage 1 and Stage 2 should be reversed. Developing, maintaining, and implementing a plan without first conducting assessments and determining the risk is illogical. The Operating Plans should be based on the results shown of the assessments.3. There is a lack of evidence showing major damage and widespread outages due to a geomagnetic disturbance. There should be more studies performed before creating a Reliability

Organization	Question 5 Comment
	Standard in order to better determine the actual necessity of one. 4. Currently, Tri-State believes that a guidance document would be a better solution to address the risk of potential geomagnetic disturbances.5. Tri-State believes all non-BES transformers should be excluded regardless of high side voltage. In addition any transformer with a delta primary winding should be excluded regardless of the high side voltage.
Independent Electricity System Operator	1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.If Requirement R5 was to be retained, we suggest adding “Reliability Coordinator” after “Transmission Operator” and “Balancing Authority”. We believe that Reliability Coordinators should also have a copy of their GMD Operating Procedures in their primary and backup control rooms. The current Requirement R5 does not include the Reliability Coordinator. 2. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”.The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
Ben Li Associates	1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.2. GMDs are an emerging issue. There is nothing in this standard that enables information sharing and learning. The RC plan and BA/TOP procedures should include what sensing information is in the field and the general reporting that such information gathering is done when GIC symptoms are observed. There should also be information collected following major solar events that is evaluated by the NERC technical committees. This should not be codified in the requirements, but

Organization	Question 5 Comment
	in an administrative appendix or an activity to be included in events analysis.
Salt River Project	A general comment on the Solar Cycle. It seems that the timing of the peak of the solar cycle might require more frequent review of plans and procedures. â€ƒ
Los Angeles Department of Water and Power	Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
Los Angeles Department of Water and Power	Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
Bonneville Power Administration	BPA agrees that operational procedures should be put in place but they will not have sufficient analysis of the full impact of certain actions due to certain technologies not being available at this point. Specifically, the reactive and thermal impacts of GMD on transformers.
CenterPoint Energy	CenterPoint Energy is hopeful that the SDT will agree with CenterPoint Energy’s suggested changes. With CenterPoint Energy’s suggested changes, we believe this standard can be reasonably applied throughout North America. If not, we believe the proposed standard is problematic for regions that have little or no GMD-related risk and ask that the SDT consider a proposal to exclude such regions from applicability. CenterPoint Energy understands that such a proposal would be subject to the Commission’s review and approval but the FERC Order is clear that the Commission understands that there are different risks in different regions and the Commission does not endorse or order a “one-size-fits-all” approach. CenterPoint Energy believes candidate regions to exclude from these requirements would potentially

Organization	Question 5 Comment
	include ERCOT, SERC, and FRCC. However, to re-iterate our main point, we believe this standard could be applied to all regions, even those regions with minimal GMD-related risk, if CenterPoint Energy's proposed changes are accepted. Even for those regions that have more GMD-related risk than other regions, CenterPoint Energy believes it is problematic and, at best, inefficient, for each and every Transmission Operator and Balancing Authority in such regions to attempt to develop individual Operating Procedures intended to collectively enhance the reliability of the region as a whole.
Colorado Springs Utilities	Comments on Requirement 1: o In need to include a requirement for the RC to acquire and disseminate space weather information to the applicable entities within their footprint.Comments on Requirement 3: o From the glossary; Operating Procedure (in part): "The steps in an Operating Procedure should be followed in the order in which they are presented"; Operating Process (in part): "An Operating Process includes steps with options that may be selected depending upon Real-time conditions." The language in the Standard will be what is audited to, notwithstanding what any individual utility may titles their documents. The actions which may be required during a GMD event are far better presented in an Operating Process (as defined) than an Operating Procedure (as defined). There is no way that a TOP could follow the exact same step-by-step procedure for all GMD eventualities, but that is what the "Operating Procedure" term demands.Comments on Requirement R3.1: o Need to eliminate the requirement to acquire space weather information in R3.1, and have it a part of the information that the RC would disseminate to ensure consistency and coordination from the RC.Comments on Implementation Plan:1. Need to ensure that RC develops and disseminates their plan 1st with time included to incorporate RC plan into BA/TOP/GOP plans.2. Implementation period needs to be extended from 6 months to 12 months.
Northeast Utilities	Comments on the Geomagnetic Disturbance Operating Procedure Template:Transmission Operator: Information and Indications:Triggers: External: Watch, Warning and Alert K index numbers are too low. K-index is known to be an unreliable predictor of GMD severity, however it makes no sense to activate procedures below K7.Triggers Internal: System-wide/ equipment-level: Parameters mentioned could be abnormal due to other causes. There should be corroborating evidence cause is GMD before entering procedure.Actions Available to the Operator: Should specify that the actions are not limited to those listed.Long lead-time: Safe system posturing (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area

Organization	Question 5 Comment
	to ensure that other entities are not negatively impacted- not just a state estimator study.Remove shunt reactors: some systems auto switch reactors. These (and capacitors) should be left in auto so that they can respond to voltage swings.Day-of-event: Increase situational awareness: These require being able to corellate the observed parameters to equipment/ system effect before taking actionsPrepare for unplanned capacitor bank/SVC/HVDC tripping: Should add that multiple installations should be evaluated as a single contingency.Real-time actions: Safe system posturing (only if supported by study):Selective load shedding: No guidance is provided as to how this could help in a GMD.Manually start fans/pumps on selected transformers: Due to the hazard of potential catastrophic failure from static electrification caused when oil temperature is below 50 C, this section should not be mentioned.System reconfiguration (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study.Return to normal operation: Why is any time limit mentioned at all?
SPP Standards Review Group	Delete the phrase ‘and submit(ted) them for approval’ from the VSLs in R4. R4 does not require approval.
Duke Energy	Duke Energy believes that “Same Day Operations” is a more appropriate time horizon for R1 and R3.
El Paso Electric Company	EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 year long implementation period instead.
Farmington Electric Utility System	FEUS appreciates the work by the SDT team to allow entities flexibility when developing their operating procedures for mitigating GMD. The flexibility allows for entities to develop the plan that works with their system
Southern Company	For R3.1, to address potential confidential data issues, the weather data utilized should be publicly available . We recommend changing R3.1 as follows:R3.1 The steps or tasks for the acquisition and dissemination of publicly available space weather information to its System Operators.

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NextEra Energy	For the same reasons provided in response to question number #4 (P81 -- administrative in nature), NextEra requests that the following requirement be deleted: R5. Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date.
Public Utility District No. 2 of Grant County, WA	GCPD is concerned about the implementation period being sufficient to allow the RC to develop and implement a GMD Operating Plan AND afford adequate time to ensure that each TO and BA within its region the ability to develop, maintain and implement GMD Operating Procedures that are coordinated with the RC's GMD Operating Plan. Six (6) months is not sufficient time to allow development and coordination within the region.
Great River Energy	GRE agrees with ACES, The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on “Real-time conditions”. A operating plan contains operating procedures and processes.
Arizona Public Service Company	Implementation time for BA and TOP should have 6 additional months than the implementation time for Reliability coordinator. This is to allow coordination wiht Reliability Coordinator’s procedures affecting BA and TOP.Requirement R1, 1.2 should have the word “all” deleted. It does not serve any specific purpose and could become unnecessarily burdensome.
American Electric Power	In the VSL matrix, R4 states that “the responsible entity reviewed its GMD Operating Procedures and submitted them for approval....”. Requirement 4, as stated, does not require approval for the Operating Procedures, therefore the words “and submitted them for approval” should be deleted from all four VSLs for R4.

Organization	Question 5 Comment
Luminant Generation	Luminant has voted Negative as the posting and balloting of the GMD proposed standard did not follow the NERC Rules of Procedure. Luminant appreciates the technical work of the Ad Hoc group but believes the standard should have been posted for comments only, instead of being posted for balloting.
Texas Reliability Entity	Many new Standards have a Guidelines and Technical Basis section as part of the Standard. Would the SDT consider creating a Guidelines and Technical Basis section?
LCRA Transmission Services Corp	none
National Rural Electric Cooperative Association (NRECA)	NRECA is does not believe that it is necessary to develop a separate GMD standard to address requiring Operating Procedures for GMD events. Criteria for addressing such events can easily be added to existing standards that require entities to have Operating Procedures. Suggesting a new standard that has similar requirements as existing standards does not adhere to the spirit of the P81 initiative to eliminate unnecessary duplicative requirements. Examples of requirements that could be revised to address GMD events are: IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other Reliability Coordinators. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. R5 - NRECA agrees that it is reasonable to require that a copy of an applicable entity's GMD Operating Procedures is in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date. In the Time Horizon designation for the requirements of this standard, the "Long Term Planning" horizon should be removed. As written, this standard addresses Operating Procedures to address Real-time events not those that meet the criteria for a "Long Term" event.
City of Austin dba Austin Energy	Overall, AE has voted negative because there is an abundance of cleanup work necessary. AE asks the SDT to consider the comments above as well as the following points:(1) The SDT should more carefully consider the wording for the applicability of transformers. During the webinar, someone asked if the intent was to cover only BES tranformers and Mark Olsen answered in the affirmative. As written, the BES definition considers the low-side voltage (greater than or equal to 100 kV), whereas the Applicability section of EOP-010-1 considers only the high-side voltage. There could be transformers that are 69/230

Organization	Question 5 Comment
	kV that would not be BES Elements but would bring in a TOP or BA given the way 4.1.2 and 4.1.3 are currently written. Additionally, the SDT should consider transformers with high and low-side voltages greater than 100kV but excluded from the BES based on a documented exclusion or exception.(2) Given the requirement to “develop, maintain and implement” in R1 and R3, the SDT should consider adding in the same day operations time horizon to cover the "implement" action.(3) The SDT should clarify what is intended by “implement” in R1 and R3. During the webinar, the response to this question was unclear. SDTs on other recent projects (COM-003-1, for example) have gone to great lengths to define what is meant by "implement." RSAWs often state it means to include in your company’s body of operating procedures. Without explanation, a CEA might interpret implement as follow your Plan/Procedure exactly as written. The industry needs to know the SDT’s intent.(4) Change the word “all” to “applicable” before the phrase “Transmission Operators and Balancing Authorities” in R1 part 1.2.(5) The SDT should move the requirement regarding space weather (currently R3 part 3.1) to R1 so the RC can, in its coordination role, ensure that input data is consistent and applicable to its Region.
Emprimus LLC and Volkmann Consulting	R5 should be applicable to RC also.
The United Illuminating Company	Requirement R5 to make the operating plan available in the control center is administrative. Reliability requires the plan to be implemented as described in requirement R1. VRF for R1 and R3 are Medium since an entity failure to implement the GMD operating plan may lead to cascade. VRF for R2, R4, and R5 should be Low. R2, R4, and R5 are purely administrative. The entity is required to have Operating Plans that mitigate the effects of GMD a review of the operating plan is a secondary activity to developing, maintaining, and implementing an operating plan.
Minnkota Power Cooperative, INC.	See NSRF Comments
Western Electricity Coordinating Council	Six Month implementation period is not adequate
Sacramento Municipal	SMUD also has concerns with the implementation period and questions whether or not six months is

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Utility District	adequate time for the BA and TOP to develop the required GMD Operating Procedures and for the RC to develop the required Plan to coordinate those GMD Operating Procedures. SMUD also encourages the SDT to consider the GMD threshold application to be raised to 300+kV,and also encourages the Project 2013-03 Standard Drafting Team to consider the comments submitted by Florida Municipal Power Agency (FMPA) related to applicability of the standard.
City of Tallahassee	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
City of Tallahassee	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
City of Tallahassee - Electric Utility	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. This reference is valuable to entity wishing to make an informed vote.
Transmission Agency of Northern California	TANC appreciates the performance flexibility that has been built into the current draft of this standard, but has concerns regarding the approximately six month implementation period between its approval and effective date. Of particular concern is the ability for each Reliability Coordinator to ensure coordination and compatibility between its GMD Operating Plan and the GMD Operating Procedures for all Transmission Operators and Balancing Authorities in its footprint during such an abbreviated period. As this initiative moves forward, TANC requests that NERC continue to carefully consider the scope of entities and assets that will be subject to this and subsequent standards so that the costs borne by the

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	industry are commensurate with the anticipated benefit to reliability.
FirstEnergy	The comments are supported by the following GMD standard ballot body members representing FirstEnergy: Bill Smith, Segment 1 Transmission Owners; Cindy Stewart, Segment 3 Load Serving Entities; Doug Hohlbaugh, Segment 4 Transmission Dependent Utilities; Ken Dresner, Segment 5 Electric Generators and Kevin Querry, Segment 6 Brokers, Aggregators, and Marketers.
Xcel Energy	The current IRO-005-3.1a R3 requires RCs to notify TOPs and BAs of certain GMD events. Consider deleting this requirement in IRO-005-3.1a as part of this implementation plan and add something in this standard (EOP-010) requiring RCs to make that notification. The pending approval of IRO-005-4 removed the explicit requirement, but development history indicates that it considers GMD to have an Adverse Reliability Impact that would require RC notification to entities.
Foundation for Resilient Societies	The Foundation for Resilient Societies has concerns that the NERC Planning Application Guide, developed without full public access to the related model assumptions, will mis-characterize geomagnetic latitudes with geographic latitudes; and will result in scientifically invalid assumptions that the NERC modeled "operating procedures" will suffice without need for hardware protections. For our Foundation review of the Draft NERC GMD Planning Application Guide, our review dated August 9, 2013, see: http://resilientsocieties.org/images/Resilient_Societies_Comments_on_GMD_Planning_Application_Guide_Final.pdf.
Hydro One Networks Inc.	There is a GMD related pre-existing requirement in IRO-005-3.1a R3. It seems, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF.The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date ",or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." to the end of the first sentence immediately after "by applicable regulatory authorities".The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
Northeast Power	There is a GMD related pre-existing requirement in IRO-005-3.1a R3. The implementation plan is not clear

Organization	Question 5 Comment
Coordinating Council	regarding the retirement of the requirement. It would seem, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF.Simpler wording would make the Standard easier to understand. Every plan will be different depending upon a wide range of factors affecting GMD mitigation; equipment types and inventory, location, system configuration and topography, latitude, ground characteristics, etc. Suggest the following simplifying wording changes to Requirement R3:R3. Each Transmission Operator and Balancing Authority shall develop, maintain, and implement GMD Operating Procedures. At a minimum, the Operating Procedures shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning] 3.1. The steps or tasks for the acquisition and dissemination of space weather information to its System Operators. 3.2. The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan. 3.3 The predetermined trigger conditions for initiating and terminating steps or tasks in the Operating Procedure.To be consistent with the terminology in other standards, suggest changing the wording the Applicability Section to:4.1.2 Balancing Authority with a Balancing Authority Area that includes transformers with high voltage terminals connected at 200kV and above.4.1.3 Transmission Operator with a Transmission Operator Area that includes transformers with high voltage terminals connected at 200kV and above.The wording of the Purpose should be changed to "To mitigate the risk of instability, uncontrolled separation, and Cascading in the Bulk-Power System as a result of geomagnetic disturbance (GMD) events by developing, maintaining and implementing Operating Plans and Operating Procedures." The Purpose as written should state what GMD affects. It also only addresses the implementation of the Operating Procedures but does not address the development and maintenance aspect, nor does it address the Operating Plans.
Northern California Power Agency	To suumarize:I will vote no on the initial ballot per comments I have submitted; however that does not mean I am opposed to this standard. I do believe GMD is an issue that even though it is low frequency can have an reliabiilty impact on the BES or BPS.I believe the SDT needs to address the IRO-005-3 R3 concern I have discussed. If I were to guess the reason for EOP-010-1, it would be to replace a pretty loose requirement in IRO-005-3 R3. If this is the case then give more direction and guidance in the new standard per the guidance document that NERC provided
Bureau of Reclamation	WAPA and Reclamation also believe that Generator Operators should have a role in developing Operating

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	Procedures that will affect their equipment.
Ameren	We believe GMD is a regional issue and therefore a NERC Standard is not necessary. We believe that studies need to be completed before considering a new NERC Standard. In addition, an entity cannot develop operating plans and procedures based on unstudied GMD conditions. After the initial assessments of potential impacts of GMD on BES reliability is complete, then appropriate (if necessary) plans and procedures can then be developed and if necessary a standard could then be drafted based on results of the studies.
MRO NERC Standards Review Forum (NSRF)	Would like clarification of the statement “last effective date” in the Table of Compliance Elements, Rows 2 and 4. Change the sentence to the following:”The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective date of the procedures”