Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Mitigation

The Geomagnetic Disturbance (GMD) Mitigation Standard Drafting Team (SDT) thanks all commenters who submitted comments on the standard. Project 2013-03 is developing 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:

- EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014. This first stage standard in the project will require applicable registered entities to develop and implement Operating Procedures.

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance events is being developed to meet the Stage 2 directives. The proposed standard 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. If the assessments identify potential impacts, the standard(s) will require the registered entity to develop corrective actions to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

TPL-007-1 was posted for a 45-day public comment period from August 27, 2014 through October 10, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 58 sets of comments, including comments from approximately 175 people from companies and organizations representing all 10 Industry Segments as shown in the table on the following pages.

Summary Consideration:
The SDT appreciates the careful review and constructive comments from stakeholders. This active participation is critical to meeting the project scope outlined in the Standard Authorization Request (SAR) and all FERC directives prior to the January 21, 2015 filing deadline.

The drafting team made the following changes to the proposed standard and supporting material:

- Geomagnetically-induced current (GIC) threshold for thermal assessments. The SDT has revised the effective GIC value for applicable Bulk Electric System (BES) power transformers requiring thermal impact assessments from 15 A per phase to 75 A per phase. Justification is provided in the revised Thermal Screening Criterion white paper.

- Transformer thermal impact assessment. The SDT has revised the Transformer Thermal Impact Assessment white paper to include a simplified method for performing a transformer thermal assessment.
- Requirements R1 through R4 contains editorial changes for clarity.
- Requirement R5 has been revised to be consistent with the 75 A per phase GIC threshold for transformer thermal assessments. The planning entity is no longer required to provide GIC time series to all Transmission Owners and Generator Owners, but must do so upon request.
- Requirement R6 has been revised to include the 75 A per phase GIC threshold for transformer thermal assessments.
- Requirement R7 contains editorial changes for clarity.
- Evidence retention periods have been revised.
- The VRF for Requirement R2 has been changed from Medium to High. This change is for consistency with the corresponding requirement in TPL-001-4, which was raised to High in response to FERC directive. (See NERC's filing of dated August 29, 2014 under RM12-1-000)
- Rationale boxes and the Application Guidelines section have been revised to provide additional explanations.

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

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

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

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Wayne Sipperly	New York Power Authority	NPCC	5
10.	Mark Kenny	Northeast Utilities	NPCC	1

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

11. Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
12. Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13. Bruce Metruck	New York Power Authority	NPCC	6
14. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

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

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton	NERC Compliance Policy	NPCC	5, 6
2. Connie Lowe	NERC Compliance Policy	RFC	5, 6
3. Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
4. Chip Humphrey	Power Generation Compliance	NA - Not Applicable	5
5. Jarad L Morton	Power Generation Compliance	RFC	5
6. Larry Whanger	Power Generation Compliance	SERC	5
7. Larry Nash	Electric Transmission Compliance	SERC	1, 3
8. Jeffrey N Bailey	Nuclear Compliance	NA - Not Applicable	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

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

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

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

6. Richard Hoag	FirstEnergy Corp.	RFC	NA
7. Chris Pilch	FirstEnergy Corp.	RFC	NA
8. Mike Miller	FirstEnergy Corp.	RFC	NA

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
7.	Group	David Greene	SERC Planning Standards Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren		
2.	Phil Kleckley	SCE&G's		
3.	Shih-Min Hsu	Southern Company Services		
4.	Jim Kelley	PowerSouth		
5.	Darrin Church	TVA		
6.	David Greene	SERC		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	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.	John Boshears	City Utilities of Springfield	SPP	1, 4
3.	Jerry Bradshaw	City Utilities of Springfield	SPP	1, 4
4.	Derek Brown	Westar Energy	SPP	1, 3, 5, 6
5.	Kevin Foflygen	City Utilities of Springfield	SPP	1, 4
6.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
7.	Jonathan Hayes	Southwest Power Pool	SPP	2
8.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
9.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
10.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
11.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
12.	Shannon Mickens	Southwest Power Pool	SPP	2
13.	James Nail	City of Independence, MO	SPP	3, 5
14.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4

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

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim 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.	Randy Hahn	Ocala Utility Services	FRCC	3
6.	Don Cuevas	Beaches Energy Services	FRCC	1
7.	Stanley Rzad	Keys Energy Services	FRCC	4
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Matt Culverhouse	City of Bartow	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steven Lancaster	Beaches Energy Services	FRCC	3
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Authority	FRCC	5

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Colby Bellville	Duke Energy	X		X		X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Bedder	Orange & Rockland Utilities (ORU)	NPCC	NA

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

2. David Burke	Rockland Electric	RFC	NA

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Greg Campoli	IRC SRC		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Cheryl Moseley	ERCOT	ERCOT	2
2. Ben Li	IESO	NPCC	2
3. Matt Goldberg	NEISO	NPCC	2
4. Charles Yeung	SPP	SPP	2
5. Ali Miremadi	CAISO	WECC	2
6. Terry Bilke	MISO	MRO	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Peter A. Heidrich	FRCC GMD Task Force										X

Additional Member	Additional Organization	Region	Segment Selection
1. Carol Chinn	Florida Municipal Power Agency	FRCC	3, 4, 5, 6
2. Carl Turner	Florida Municipal Power Agency	FRCC	3, 4, 5, 6
3. Bret Galbraith	Seminole Electric Cooperative	FRCC	1, 3, 4, 5, 6
4. Ralph Painter Jr.	Tampa Electric Company	FRCC	1, 3, 5, 6
5. Jow Ortiz	Florida Power & Light	FRCC	1, 3, 5, 6
6. Ignacio Ares	Florida Power & Light	FRCC	1, 3, 5, 6

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

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3

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

3.	John Babik	FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Erica Esche	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	X		X		X					

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Brian Van Gheem	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ginger Mercier	Prairie Power, Inc.	SERC	3
2.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
3.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
4.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
7.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
8.	John Shaver	Arizona Electric Power Cooperative	WECC	1, 4, 5
9.	John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
10.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	John allen	Iberdrola USA			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Julie King	New York State Electric & Gas	NPCC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Richard Becker	Substation Engineering	WECC	1
2.	Berhanu Tesema	Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Group	William R. Harris	Foundation for Resilient Societies								X		

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
24.	Individual	Dr. Gabriel Recchia	University of Memphis										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
26.	Individual	Thomas Lyons	Owensboro Municipal Utilities			X							
27.	Individual	Terry Volkmann	Volkmann COnsulting								X		
28.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
29.	Individual	Bill Daugherty	Concerned citizen										
30.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co.			X	X	X					
31.	Individual	John Merrell	Tacoma Power	X									
32.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
33.	Individual	David Jendras	Ameren	X		X		X	X				
34.	Individual	Eric Bakie	Idaho Power	X									
35.	Individual	Terry Harbour	MidAmerican Energy Company	X		X							
36.	Individual	Karin Schweitzer	Texas Reliability Entity										X
37.	Individual	Alshare Hughes	Luminant Generation Company, LLC					X	X	X			
38.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
39.	Individual	John Bee on Behalf of Exelon and its Affiliates	Exelon	X		X		X					
40.	Individual	Richard Vine	California ISO		X								
41.	Individual	PHAN, Si Truc	Hydro-Quebec TransEnergie	X									
42.	Individual	John Pearson/Matt Goldberg	ISO New England		X								
43.	Individual	David Kiguel	David Kiguel								X		
44.	Individual	Bill Fowler	City of Tallahassee			X							
45.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
46.	Individual	Mark Wilson	Independent Electricity System Operator		X								
47.	Individual	Scott Langston	City of Tallahassee	X									
48.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
49.	Individual	Karen Webb	City of Tallahassee					X					
50.	Individual	Bill Temple	Northeast Utilities	X									
51.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
52.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
53.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
54.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
55.	Individual	Catherine Wesley	PJM Interconnection		X								
56.	Individual	Gul Khan	Oncor Electric	X									
57.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
58.	Individual	Wayne Guttormson	SaskPower	X									

1. TPL-007-1. Do you agree with the changes made to TPL-007-1? If not, please provide a specific recommendation for revisions you could support and justification to support the proposed revisions.

Summary Consideration: The SDT responded to commenters who raised the following issues:

Underground Transmission. The standard does not specifically address underground transmission lines. The SDT agrees that underground transmission lines are different, should not be modeled as GIC sources, but will conduct GICs. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.

Encouragement of the Use of Regional Collaborative Processes. Commenters suggested that the SDT reinforce the use of regional collaborative processes to accomplish the requirements of the standard. The SDT encourages these processes and has added suggested language to the rationale box to reinforce this position.

Analyses which Span Large Areas. Commenters identified the challenges of performing the required analyses for large systems. The SDT acknowledges this difficulty and offers that flexibility exists in the standard to carry out these analyses in various ways, but also that the presently available power system analysis software allows for varying parameters.

Transformer Thermal Assessments. A number of commenters identified limitations associated with performing the transformer thermal assessments and the potential for heavy dependency on the transformer manufacturers. Transformer manufacturers provided input on the thermal assessment threshold and approach to conducting thermal assessments. In response, the SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.

Specific Identification of Responsible Entities in the Requirements. Commenters suggested specific identification of responsible entities in the requirements in lieu of use of the term "responsible entities". The SDT agrees with the need to be specific in the identification of responsibilities, but recognizes that there are a myriad of organizational structures that subvert the ability to provide specific identification. The SDT continues to believe that the definition of responsibilities required in R1 is the best way to accomplish the objective.

Execution of the Corrective Action Plan. Commenters suggested that the SDT include requirements that address the completion of the Corrective Action Plan. The TPL standards do not address the execution of Corrective Action Plans prepared by the planning entities. Since this standard in part applies to the Generator Owners and Transmission Owners, it was suggested that the standard needs to include requirements related to the execution of the Corrective Action Plan. Other comments suggested that the SDT would be granting new authority to the planning entities if the planning entities were responsible for the execution of the Corrective Action Plan. The concerns relate to the authority of the planning entities to require what could be substantial investments to mitigate the impacts of GMD. Normally, those types of decisions are made by the asset owner, outside of the planning process. The SDT believes that the investment decisions in the case of the GMD Corrective Action Plan will require a collaborative process outside of this standard. To do otherwise would grant additional authority to the planning entities that was not intended and which they do not possess today. The planning entities may use existing processes to address investment decisions, if any.

Harmonics Analysis. Commenters suggested that the tools and capability to perform harmonics analysis are inadequate. The SDT acknowledges that harmonics analysis is a technical specialty and comprehensive harmonics analysis tools and capability are not in wide availability in the industry. However, the SDT believes that some basic harmonics knowledge can be applied in the GMD Vulnerability Assessment process and is necessary to address this reliability risk. FERC Order No. 779 specifies that the vulnerability assessments must account for the effects of "harmonics not present during normal BPS operation." The standard should not take a prescriptive approach on the technical details, but rather refer to the available information. In this case, the GMD Planning Guide and 2012 GMD TF Interim Report provide general considerations for the planner to use (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council Con Edison, Inc	No	The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type

Organization	Yes or No	Question 1 Comment
		transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type transmission feeders. There can be an adjustment factor within the power flow model to reduce the impact of the induced electric field from one (full effect) to zero (full shielding) as necessary and appropriate.On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads:"Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network model."Suggest adding the following paragraph afterwards:"Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model." This comment was submitted during the last comment period.

Response: The SDT agrees that underground pipe-type cables should not be modeled as GIC sources. GIC, induced in the pipe, will circulate through the pipe, cathodic protection and ground return circuit, but it is probably an order of magnitude lower than what

Organization	Yes or No	Question 1 Comment
be induced in an unshielded transmission circuit. However, the cables will carry GIC induced elsewhere (overhead circuits) and must be included in the dc network (but not as dc sources) as well as the load flow base case. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.		
Colorado Springs Utilities	No	1.) Requirement 4.3 should have to be shared upon request only.We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: The SDT agrees with the comment that encourages regional planning groups to work collaboratively to address the requirements in the standard. The SDT believes that it has provided the flexibility in the standard to support that kind of effort. Regarding the sharing of information among entities, the SDT believes that mandatory sharing of the GMD Vulnerability Assessment is necessary for the RC, adjacent PC, and adjacent TPs to ensure that those entities are aware of information that may be germane to their respective analyses. Other entities can receive the information upon request. In order to better address the comment, the SDT is providing additional clarifying information in the Rationale for Requirement R1. A Rationale box is proposed: ***Rationale for Requirement R1****:* *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		
SERC Planning Standards Subcommittee	No	On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Louisiana as for Minnesota, while conservative, would be absurd. Some sanity in this regard must be maintained among the functional entities to whom this

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>standard would be applicable, particularly for PC’s and their associated TP/TO entities.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that to model a transmission network that spans more than one degree of geomagnetic latitude with the highest alpha value would be very conservative. Commercial software allows users to use different V/km (and thus alpha factors and earth models) in different parts of the network. If an applicable entity can justify (technically) the use of different Epeak values in the model, the standard provides the flexibility of doing so. The specific section in Attachment 1 states:

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

• calculated by using the most conservative (largest) value for α; or
• calculated assuming a non-uniform or piecewise uniform geomagnetic field.</td></tr>
<tr><td>SPP Standards Review Group

Kansas City Power and Light</td><td>No</td><td>5. Background - Replace ‘Misoperation’ with ‘Misoperation(s)’.R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 - set the phrase ‘as determined in Requirement R1’ off with commas.R4 - Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load.Rationale Box for Requirement R4 - Capitalize ‘On-Peak’ and ‘Off-Peak’.Measure M5 - Insert ‘in the Planning Area’ between ‘Owner’ and ‘that’ in the next to last line of M5.Rationale Box for Requirement R5 - Capitalize ‘Part 5.1’ and ‘Part 5.2’. Likewise, capitalize ‘Part 5.1’ under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section.R6/M6 - Capitalize ‘Part 5.1’. Attachment 1 - We thank the drafting team for providing more clarity in the determination of the Î² scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic - When referring to</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Response: The SDT has made several editorial changes. However, some of the suggested changes did not meet the NERC style guide and were not changed. Regarding the question on the number of On Peak and Off Peak studies required, the intent of the SDT was to require that one On Peak and one Off Peak case be studied during the 5 year period. The rationale box has been changed to clearly indicate the SDT's intent: *At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.*		
PPL NERC Registered Affiliates	No	Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. 1. The tools available for GOs and TOs to perform the transformer thermal impact assessments of TPL-007-1 requirement 6 are presently inadequate. There are two approaches for such work, as stated on p.4 of NERC's Transformer Thermal Impact Assessment White Paper: use of transformer manufacturer geomagnetically-induced current (GIC) capability curves, or thermal response simulation. We (and probably almost all entities) have no manufacturer GIC data, and the simulation approach requires, "measurements or calculations provided by transformer manufacturers," or, "conservative default values...e.g. those provided in [4]." Reference 4 includes only a few case histories and not widely-applicable transfer functions. Nor does there exist a compendium of, "generic published values," cited on p.9 of the White Paper. Performing thermal response experiments on in-service equipment is out of the question; so enacting TPL-007-1 in its present state would produce a torrent of requests for transformer OEMs to perform studies, this being the only available path forward. We anticipate that

Organization	Yes or No	Question 1 Comment
		each such study would require several days of effort by the OEM and cost several thousand dollars, which would be impractical for addressing every applicable transformer in North America. Generic thermal transfer functions are needed, and the SDT representatives in the 9/3/14 teleconference with the NAGF standards review team agreed, adding that the Transformer Modeling Guide (listed as being "forthcoming" in NERC's Geomagnetic Disturbance Planning Guide of Dec. 2013) will become available prior to the time that GOs and TPs must perform their analyses.We have to base our vote regarding TPL-007-1 on the standard as it presently stands, however. We do not know whether or not the Transformer Modeling Guide will prove suitable, nor is there any guarantee that it will ever be published. We suggest that the standard be resubmitted for voting when all the supporting documentation is available. 2. TPL-007-1 calls for PC/TPs to provide GIC time series data (R5), after which TO/GOs perform thermal assessments and suggest mitigating actions (R6). The PC/TPs then develop Corrective Action Plans (R7), which are not required to take into account the TO/GO-suggested actions and can include demands for, "installation, modification, retirement, or removal of transmission and generation facilities." The SDT representatives on the NAGF teleconference cited above stated that granting PC/TPs such sweeping powers over equipment owned by others is consistent with the precedent in TPL-001-4; but we disagree - TPL-001-4 is not even applicable to GOs and TOs. We have high regard for PC/TPs, and we agree that they should be involved in developing GMD solutions, but proposing to give them unilateral control over decisions potentially costing millions of dollars per unit is inequitable. This point is substantiated by the input from Dr. Marti of Hydro One (author of the reference #4 cited above) that they have never had to replace transformers for GMD mitigation; such actions as operational measures, comprehensive monitoring, real time management and studies have been sufficient.

Organization	Yes or No	Question 1 Comment
Response: 1. In order to simplify and facilitate the completion of the transformer thermal assessments, the SDT is proposing two significant changes to the process: (1) the threshold for requiring the performance of a thermal assessment is being raised from 15 amps per phase to 75 amps per phase; and (2) a simplified thermal assessment method based on available models is provided which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.. The above changes should dramatically reduce the number of transformers for which a more detailed thermal assessment is required and will not require the assistance of the transformer manufacturers to execute. Please see the Transformer Thermal Assessment white paper Thermal Screening Criterion for the technical justification for making these changes. 2. Regarding the comment that the standard will be granting new expanded powers to the Planning Coordinator that do not exist today, the SDT responds that it was not the intention of the SDT to grant any additional authority to the PC that they do not presently have under the TPL standards. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where system performance cannot be met during the Benchmark GMD conditions. However, as with other TPL standards, the standard does not address the execution of the CAP. Normally, investment decisions are made by the asset owner outside of the planning process. The SDT believes that the investment decisions in the case of the GMD Corrective Action Plan will require a collaborative process outside of this standard. To do otherwise would grant additional authority to the planning entities that was not intended and which they do not possess today. The planning entities may use existing processes to address investment decisions, if any.		
IRC SRC	No	1. The ISO/RTO Standards Review Committee (SRC) respectfully submits that the modifications to the measure remove the ability of Planning Coordinators to vet and implement protocols that are broadly applicable to Transmission Planners in its footprint through a consensus process. The requirement to develop individual protocols in coordination with each and every Transmission Planner individually creates unnecessary and unduly burdensome administrative processes that lack a corresponding benefit. The requirement and measure should be modified to allow Planning Coordinators to utilize consensus processes generally and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, th SRC notes that the modeling data

Organization	Yes or No	Question 1 Comment
		itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since that standard deals with load flow, stability, and short circuit data. Accordingly, the SRC recommends that requirements R2 and R3 from MOD-032 be added as requirements in the beginning of the GMD standard and substitute the word “GMD” where it states “steady-state, dynamic, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. In addition to adding the requirements noted above, the below revisions are proposed:R1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall delineate the individual and joint responsibilities of the Planning Coordinator and these entities in the Planning Coordinator’s planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). [Violation Risk Factor: Low] [Time Horizon: Long-term Planning] M1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and copies of procedures or protocols in effect that identifies that an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.Corresponding revisions to VSLs are also recommended. 2. The SRC notes that the use of the term “Responsible Entities” “as determined under Requirement R1” is ambiguous and could be modified to be more clearly stated. The below revisions are proposed:”Entities assigned the responsibility under Requirement R1”Corresponding revisions for associated measures and VSLs are also recommended. 3. The SRC respectfully reiterates its comment 2 above regarding the term “Responsible Entities” “as determined under Requirement R1” and recommends

Organization	Yes or No	Question 1 Comment
		that, for all instances where "Responsible Entity" is utilized in Requirement R3, similar revisions are incorporated. Corresponding revisions for associated measures and VSLs are also recommended. 4. The SRC respectfully reiterates its comment 3 above for all instances where "Responsible Entity" is utilized in Requirement R4. It further notes that Requirement R4 is ambiguous as written. More specifically, the second sentence could more clearly state expectations. The following revisions are proposed:R4. Entities assigned the responsibility under Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, include documentation of study assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] Corresponding revisions for associated measures and VSLs are also recommended. 5. The SRC respectfully reiterates its comment 3 above for all instances where "Responsible Entity" is utilized in Requirement R5. Additionally, for Requirement R5, no timeframe is denoted for provision of the requested data. To ensure that requested or necessary data is provided timely such that it can be incorporated in the thermal assessment required pursuant to Requirement R6. It is recommended that the requirement be revised to include a statement that the data is provided by a mutually agreeable time. Corresponding revisions for associated measures and VSLs are also recommended. 6. The SRC respectfully submits that, as written, Requirement R6 appears to require an individual analysis and associated documentation for each power transformer and does not allow Transmission Owners and Generator Owners to gain efficiencies by producing a global assessment and set of documentation that includes all required equipment. It further does not allow these entities to collaborate and coordinate on the performance of jointly-owned equipment, creating unnecessary administrative burden and reducing the exchange of

Organization	Yes or No	Question 1 Comment
		information that could better inform analyses. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5; 6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and 6.4. Be performed and provided to the responsible entities as determined in Requirement R1 within 24 calendar months of receiving GIC flow information specified in Requirement R5. Corresponding revisions for associated measures and VSLs are also recommended. 7. As a global comment, the confidentiality of the information exchanged pursuant to the standard should be evaluated and, if necessary, the phrase “subject to confidentiality agreements or requirements” inserted in Requirements R3 through R7. Corresponding revisions for associated measures and VSLs are also recommended.
Response: 1. The SDT agrees with the comment that encourages regional planning groups to work collaboratively to address the requirements in the standard. The SDT believes that it has provided the flexibility in the standard to support that kind of effort. The SDT reviewed MOD-032 and decided not to include portions of the standard as suggested in the comment. The SDT believes that		

Organization	Yes or No	Question 1 Comment
MOD-032 is intended to address data more generally than is considered in the comment. TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements for steady state analysis and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes. Future revisions of MOD-032 should be updated to maintain a single modeling standard 2-5. The SDT agrees with the comment on the use of the term “responsible entities” and will make changes as suggested. 6. The SDT agrees with the first part of the comment and revised the wording in the standard to clarify that documentation covering all applicable BES power transformers could be used to satisfy the requirement. 7. Confidentiality of information is covered under NERC Rules of Procedure, so the SDT did create a requirement to duplicate the provisions. However, rationale boxes have been updated with guidance.		
ACES Standards Collaborators	No	(1) We would like to thank the SDT for already addressing many of our concerns regarding the previous drafts of this standard. However, we still have a concern regarding how the applicable entities are identified in this standard and recommend the SDT designate the Planning Coordinator as the applicable entity for compliance with Requirement R1. R1 lists both the PC and the TP as concurrently responsible for compliance, yet the NERC Functional Model clearly identifies that the PC “coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.” We further recommend that the PC, because of its wide-area view, should be the entity responsible for performing the GMD Vulnerability Assessment. The SDT identifies their justification for this approach is the same as the one taken in other planning standards, and while we appreciate an effort to maintain consistency between standards, this approach has forced many entities to plan and implement formal coordination agreements between PCs and TPs on a regional basis to identify the responsibilities of conducting these assessments. The approach spreads the burden of compliance among many entities rather than directly assigning the responsibilities to just a smaller set, the Planning Coordinators. We believe the SDT should remove each reference to “Responsible entities as determined in Requirement R1” and instead properly assign the PC.(2)

Organization	Yes or No	Question 1 Comment
		We appreciate the SDT providing their justifications for a facility criterion with the applicability of this standard; however, we believe the SDT should remove this criterion and instead utilize the current BES definition that went into effect on July 1, 2014. Like the SDT, we also acknowledge that parts of the proposed standard apply to non-BES facilities and that some models need such information to accurately calculate geomagnetically-induced currents. However, that criterion should be identified within the Guidelines and Technical Basis portion of the standard. Adding the facility criterion upfront in the applicability section of the standard provides confusion to both industry and auditors when 200 kV high-side transformers may apply. The BES definition identifies all Transmission Elements operated at 100 kV or higher and accounts for inclusions and exclusions to that general definition. The SDT should leverage the technical analysis that was performed to achieve industry consensus and FERC approval for the revised BES definition. The current approach only provides additional confusion.
Response: The SDT reconsidered the use of the term “responsible entities” and while it agrees with the concept of specifically identifying the entities who will have the responsibility to perform, the SDT did not feel that it could change the terminology due to the diversity of how the entities are organized in the North American system. The SDT continues to believe that the respective responsibilities need to be sorted out via group discussions facilitated by the Planning Coordinator as envisioned in R1.		
Foundation for Resilient Societies	No	COMMENTS OF THE FOUNDATION FOR RESILIENT SOCIETIES (Comment 1 of 2 submitted 10-10-2014)TO THE STANDARD DRAFTING TEAM NERC PROJECT 2013-03 - STANDARD TPL-007-1TRANSMISSI0N SYSTEM PLANNED PERFORMANCE FOR GEOMAGNETIC DISTURBANCE EVENTSOctober 10, 2014Answer to Question 1: No, we do not agree with these specific revisions to TPL-007-1. Detailed responses are below. 1. Requirement R3 should contain steady state voltage “limits” instead of the subjective term “performance.” Measure M3 should contain steady state voltage “limits” instead of the subjective term “performance.”

Organization	Yes or No	Question 1 Comment
		2. Table 1, “Steady State Planning Events” has been changed to allow “Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service” as primary means to achieve BES performance requirements during studied GMD conditions. When cost-effective hardware blocking devices can be installed, load loss should not be allowed. Protective devices that keep geomagnetic induced currents (GICs) from entering the bulk transmission system extend service life of other critical equipment, allow equipment to “operate through” solar storms, reduce reactive power costs and support higher capacity utilization. In contrast, load shedding while GSU transformers remain in operation tend to reduce equipment life and continue to allow GICs into the bulk power system, risking grid instabilities. Capacitive GIC blocking devices are, to first order, insensitive to uncertainties in GMD currents and thus protect the grid against a large range of severe GMD environments. 3. Table 1, “Steady State Planning Events” has been changed to allow Interruption of Firm Transmission Service and Load Loss due to “misoperation due to harmonics.” When cost-effective hardware blocking devices can be installed, misoperation due to harmonics should be prevented. 4. On page 12, text has been changed to “For large planning areas that span more than one Î² scaling factor from Table 3, the most conservative (largest) value for Î² should may be used in determining the peak geoelectric field to obtain conservative results.” “May” is not a requirement; the verb “should” needs to be retained in the standard. 5. Under “Application Guidelines,” Requirement R6 now reads: “Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2

Organization	Yes or No	Question 1 Comment
		is also a justifiable threshold criterion that exempts a transformer from Requirement R6." These exemptions from the assessment requirements of this standard, both singly and in combination, defeat a key purpose of FERC Order No. 779, which is to protect the bulk power system from severe geomagnetic disturbances: (1) By failing to require the utilization of now-deployed and future-deployed GIC monitors, of which there were at least 102 in the U.S. in August 2014 (see Resilient Societies' Additional Facts filing, Aug 18, 2014, FERC Docket RM14-01-000), and now at least 104 GIC monitors, NERC fails to mandate use and data sharing from actual GIC readings, and cross-monitor corroboration of regional GIC levels. This systematic failure to use available risk and safety-related data may enable "low-ball modeling" of projected GIC levels both at sites with GIC monitors and at other regional critical facilities within GIC monitoring; (2) The so-called "benchmark model" developed by NERC significantly under-projects GICs and electric fields. The Standard Drafting Team, in violation of ANSI standards and NERC's own standards process manual, has failed to address on their merits, or refute with scientific data and analysis, the empirically-backed assertions of John Kappenman and William Radasky in their White Paper submitted to the Standard Drafting Team of NERC on July 30, 2014. See also the Resilient Societies' "Additional Facts" filing in FERC Docket RM14-01-000, dated Aug. 18, 2014. Using a smaller region of Finland and the Baltics as a modeling foundation, the NERC Benchmark model under-estimates geoelectric fields by factors of 1.5. To 1.9. This systematic under-estimation of geoelectric fields will have the effect of excluding entities that should be subject to the assessment requirements, thereby reducing the analytic foundation for purchase of cost-effective hardware protective equipment thus allowing sizable portions of the grid to be directly debilitated, with cascading effects on other portions of the grid. (3) In the NERC Standard Drafting Team's review of the Kappenman-Radasky White Paper submitted on July 30, 2014, the STD Notes claim: "They [the

Organization	Yes or No	Question 1 Comment
		Standard Drafting Team] did not agree with the calculated e-fields presented in the commenter's white paper for the USGS ground model and found that the commentator's result understated peaks by a factor of 1.5 to 1.9" Meeting Notes, Standard Drafting Team meeting, August 19 [20014] Comment Review, page 2, para 2b, at page 3. This is altogether garbled. The commenters, using empirical data from solar storms in the U.S. and not in Finland, found the benchmark model understated GICs and volts per kilometer by a factor of 1.5 to 1.9. The Standard Drafting Team has submitted the standard to a subsequent ballot without addressing the Kappenman-Radasky White Paper critique on its merits. This is a violation of both ANSI standards and the NERC standards process manual requirements. (4) To exempt mandatory assessments if a transformer manufacturer's design specifications claim transformer withstand tolerances above the benchmark-projected amps per phase is to place grid reliability upon a foundation of quicksand. (A) Manufacturers generally do not test high voltage transformers to destruction, so their certifications of equipment tolerances are scientifically suspect;(B) As the JASON Summer study report of 2011, declassified in December 2011, indicates: a review of the warranties included with most high voltage transformer sales contracts exclude liability for transformer failures due to solar weather, so "transformer ratings" are not guaranteed and are not backed by financial reimbursement for equipment losses or resulting loss of business claims. The JASONs concluded it was more prudent to purchase neutral ground blocking devices than to pay to test extra high voltage transformers and still risk equipment loss in severe solar weather;(C) The claims of transformer manufacturers have been disputed by national experts, so without testing by a neutral third party, such as a DOE national energy laboratory, these claims are suspect, and should not, without validated third party testing, be an allowable exclusion from mandatory assessment by all responsible entities. See, for example, the Storm Analysis Consultants Report Storm R-112, addressing various unsubstantiated claims by ABB for various transformers. Storm-R-112 noted a

Organization	Yes or No	Question 1 Comment
		number of ABB claims that could not be substantiated. Moreover, in transformer ratings provided to American Electric Power, Kappenman asserts that manufacturer reports have failed to address the most vulnerable winding on the transformer, the tertiary winding. John Kappenman informed the Standard Drafting Team that measurable GIC withstand was much lower than what the manufacturer had estimated for one tested transformer. He further explains that tests carried out by manufacturers only have been able to go up to about 30 amps per phase and were set up to actually exclude or inhibit looking at the most vulnerable tertiary winding on tested transformers. Papers submitted to IEEE and CIGRE discuss these tests but ignore the tertiary winding vulnerabilities. Hence these nonrigorous, manufacturer-biased “ratings” should not, without third party validation, exempt an entity from assessment responsibilities under this standard. (5) The submission of comments today, October 10, 2014, by John Kappenman and Curtis Birnbach, further invalidates the NERC Benchmark model as a basis to design vulnerability assessments. Both the alpha factor and the beta factor of the NERC model significantly under-project GICs and geoelectric field of anticipated quasi-DC currents. The so-called “benchmark” standard is not ready for prime time. If the Standard Drafting Team fails to address the systematic biases in its modeling effort, if it fails to utilize U.S. data and not Finland and Baltic region data, if it fails to require modeling based on the full set of 104 GIC monitors and future added GIC monitors, NERC will be in violation of its ANSI obligations and in violation of the standard validation process set forth in NERC’s own Standards Process Manual adopted in June 2013. (6) Resilient Societies reported to the GMD Task Force as far back as January 2012 that vibrational impacts of GICs were the proximate cause of a 12.2 day outage of the Phase A 345 kV three-phase transformer at Seabrook Station, New Hampshire on November 8-10, 1998. Magnetostriction and other vibrations of critical equipment are associated with moderate solar storms. A moderate North-South/South-North reversing solar storm caused ejection of a 4 inch stainless steel bolt into the winding of the Phase A transformer at Seabrook,

Organization	Yes or No	Question 1 Comment
		captured by FLIR imaging as the transformer melted on November 10, 1998. NERC's own compilations on the March 1989 Hydro-Quebec storm records contain dozens of separate reports of vibration, humming, clanging, and other audible transformer noise at locations within the U.S. electric grid at the time that the GSU transformer at Salem Unit 1 melted. More recently, tests at Idaho National Laboratory in 2012, reported by INL and SARA in scientific papers in 2013, confirm that GICs injected into 138 kV transmission lines cause adverse vibrational effects; and that neutral blocking devices eliminate these vibrational effects. It is arbitrary and capricious for the NERC Standard Drafting Team to fail to address vibrational effects of GMD events, and vibrational elimination when neutral ground blocking equipment is installed. Even if the Standard Drafting Team would prefer a standard that discourages any obligation to install neutral ground blocking devices, such an outcome does not comply with ANSI standards. Evidence-based standards are needed. Excluding an entire category of risks (magnetostriction and other vibrations) that are well documented in literature on vibrational risks in electric grids should be unacceptable to NERC, to FERC, and to ANSI. (7) The Standards Drafting Team did not act to address our comments submitted on July 30, 2014, in violation of ANSI requirements that comments be addressed. Areas not addressed include, but are not limited to:(A) No adjustment for e-field scaling factors at the edge of water bodies.(B) No standard requirement for the assessment of mechanical vibration impacts.(C) No requirement for testing of transformers to validate thermal and mechanical vibration withstand when subjected to DC current limits.(8) Our concerns with NERC's speculative "hot spot" conjecture for GIC impacts over wide areas were not addressed. Under separate cover to NERC, we are submitting data and analysis that shows NERC's "hot spot" conjecture is inconsistent with real-world data. In conclusion, we note that the Federal Energy Regulatory Commission in its Order No. 779 [143 FERC Â¶ 61,147, May 16, 2013) ordered "that any benchmark events proposed by NERC have a strong technical basis." Emphasis added,

Organization	Yes or No	Question 1 Comment
		quoting Order No. 779 at page 54.For the above reasons, among others, NERC's draft standard TPL-007-1 does not presently have a "technical basis" for its implementation, let alone a "strong technical basis" as required by FERC's Order.

Response: Thank you for your comments, we appreciate your participation in the standard development process.

1. R3 was changed in response to comments from several stakeholders. Voltage limits remain an acceptable criteria. As written, R3 accepts voltage limits and provides flexibility for development of more sophisticated methods of determining voltage stability.

2. Performance criteria in table 1 meets the directives of FERC Order 779. The SDT also believes that this criteria which permits load loss is consistent with planning criteria for other extreme events. The comment is not supported by the state of the art in hardware mitigation.

3. Performance criteria in table 1 meets the directives of FERC Order 779, as does including harmonic impacts (P.67). The comment is not supported by the state of the art in hardware mitigation.

4. The section referred to in the comment provides two alternatives that are equally acceptable, so the standard is worded appropriately.

5. The Screening Criterion white paper provides the technical explanation for the selection of the GIC threshold. The criterion is conservative which allows for significant variations by type, design, age, and other factors. A design specification for a transformer provides a reasonable technical basis for excluding a transformer from mandatory requirements for thermal assessment. However good engineering practice may indicate to an owner that a detailed assessment is warranted.

The standard addresses the assessment parameters of order 779. Vibration impacts are not included in the standard. Available information is sparse and mostly anecdotal. Available information does not suggest vibration would likely have a wide area impact.

The SDT has previously responded to comments on water bodies, vibration, transformer tests to determine thermal time constants, and the technical development of the benchmark event. As noted herein, "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

Organization	Yes or No	Question 1 Comment
an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]" Response to Supplemental Comment "NERC Request for Comments on TPL-007" (appended) To be accurate, the spatially-averaged geoelectric field amplitude is 8 V/km, not 5.77. The averaging process does not explicitly assume the existence of ionospheric hotspots. The geoelectric field is characterized in regional scales without making any assumptions about the actual field structure. Of course, localized hotspots, if they exist, will be reduced in amplitude in the averaging process as we are interested in regional-scale rather than point wise enhancements in the field. Large-scale spatially coherent enhancements would not be reduced in amplitude in the averaging process. The observation in the comment of "simultaneous GIC peaks" or "simultaneous dB/dt" has no relation with the methodology used to develop the benchmark geoelectric field amplitude (8 V/km). It is not possible, and it can be quite misleading, to analyze Figure 1 in the supplemental comment without a power system model. However, if we neglected the effects of power system topology and network resistance (which we emphasize cannot be done), we notice that Rockport measured 80 A while Kammer measured only 40 A; i.e., half the GIC magnitude of Rockport. Similarly, Figure 3 shows that OTT measured more than twice the peak amplitude dBx/dt than STJ. This is precisely why the standard contemplates wide-area spatial averages to estimate extreme geoelectric fields. It would be incorrect to define a benchmark to be applied continent-wide when we observe significant differences across the system driven by geographic (latitude and ground conductivity) and system characteristics.		
PacifiCorp	No	Please refer to the response for #4.
University of Memphis	No	I would support a version of TPL-007-1 for which the statistical analyses were recomputed to take the considerations I mention in my responses to Question 4 into account, for which the numbers in TPL-007-1 Attachment 1 were adjusted accordingly, and for which the standards were adjusted to be appropriate given the new values.

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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: See response in Question 4.</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>The proposed standard specifies no obligation that any of the applicable Functional Entities carry out the “suggested actions” in R6. It would appear that the authors of the draft RSAW concur, as the RSAW likewise shows no indications of any such obligation. While R7 does require the development and execution of a Corrective Action Plan, its applicability is limited by R1 to the PC and TP, and it is unclear if any other mechanism exists by which the PC/TP can require the TO/GO to take action.The drafting team continues to state that it is the responsibility of the owner to mitigate. If it is the expectation of the drafting team that the TO and/or GO implement the R6 “suggested actions”, the standard must be revised to clearly indicate this intention or the drafting team must clearly communicate how they envision the coordination between the PC/TP and the TO/GO occurring.TOs and GOs need to be involved in the development of the Corrective Action Plans that they will required to execute. The standard should require the PC to set up a stakeholder process with TOs and GOs related to these corrective action plans. The stakeholder process would take into account considerations such as scope of corrective action plans, schedules, market impacts, etc.</td></tr>
<tr><td colspan="3">Response: The intent of R6 is to provide planners with the necessary thermal assessment information to complete a GMD Vulnerability Assessment, which by definition includes equipment impacts. The rationale box has been revised to provide clarity.

I It is not the intention of the SDT to grant any additional authority to the PC that they do not presently have under the TPL standards. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where system performance cannot be met during the Benchmark GMD conditions. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. The reason for this is due to the fact that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction and outside the purview of reliability standards.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: There have been a number of historical events, most notably the 1989 Hydro Quebec blackout, that have been attributed to GMD. Based on those historical events, prudency dictates that the potential reliability issues associated with this phenomenon be assessed and mitigated.		
Volkmann Consulting	No	There is no technical justification to add an additional year to the process to an imminent problem.
Response: The SDT received a number of comments suggesting that the implementation plan for the standard is too short. Given that the process will require additional data, models, and assessment tools and practices that are new to the various entities, the SDT believes that that the extended implementation timeframe is reasonable.		
Seminole Electric Cooperative, Inc.	No	(1) Seminole is confused as to whether the CP-3 value has been finalized by USGS or not, as USGS's website does not reflect the CP-3 value represented in the latest ballot. If the ground conductivity value for the Florida Peninsula, CP-3, is not final, i.e., USGS is still developing and researching the value, then the drafting team should delay vote on the Standard or allow for successive balloting on the final CP-3 value when USGS finalizes its value. Seminole does not believe the NERC Standards Process Manual allows for revisions to the CP-3 value after the Standard has been approved without re-opening the balloting.(2) Seminole is aware that a CEAP is not required to be performed, however, Seminole believes a CEAP is justified in this particular circumstance.
Response: 1. The ground model for Florida has been provided. USGS is in the process of updating their website. The standard allows the use of updated models at any time as specified in Attachment 1. 2. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the		

Organization	Yes or No	Question 1 Comment
potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
Concerned citizen	No	The selection of the March 13-14 1989 GMD (Hydro Quebec) and the October 29-31 2003 Halloween events to define the 100 year GMD standards ignores a substantial body of work by researchers such as Bruce Tsurutani (NASA) and Daniel Baker (University of Colorado). NERC has chosen to define the 100 year GMD based solely on GMD events that were measured when CMEs actually hit the Earth in the 1980 to 2013 time frame. This ignores the work done by Tsurutani, Baker, and others that have quantified the magnitude of both pre 1980 events as well as events like the July 2013 event that was directed away from the Earth.The 1989 GMD was not all that strong when viewed on a historical basis, and the 2003 Halloween event, while a X17.2, resulted in a greatly dampened measured effect on the Earth's magnetic field since the magnetic component was pointing northward when it hit the Earth. Had it been pointing southward, the measured effect would have been greatly amplified.This 100 year GMD standard should not be allowed to be finalized without incorporating the findings and recommendations of papers like: Baker, D. N., X. Li, A. Pulkkinen, C. M. Ngwira, M. L. Mays, A. B. Galvin, and K. D. C. Simunac (2013), A major solar eruptive event in July 2012: Defining extreme space weather scenarios, Space Weather, 11, 585-591, doi:10.1002/swe.20097. andTsurutani, B. T., and G. S. Lakhina (2014), An extreme coronal mass ejection and consequences for the magnetosphere and Earth, Geophys. Res. Lett., 41, doi:10.1002/2013GL058825NERC has greatly underestimated the true magnitude of the 100 year threat to the electric grid from solar storms. This must be addressed before these standards are finalized.

Organization	Yes or No	Question 1 Comment
Response: The benchmark GMD event electric field was derived from a statistical analysis of actual magnetometer measurements taken over the course of almost 20 years and extrapolated to the point of 1 in 100 year probability. It was not based on the March 1989 event. However, the March 1989 event was used for the benchmark event time series because it provides a set of high fidelity data that provides conservative results.		
Ameren	No	We still strongly feel that a GMD event of 4-5 times the magnitude of the 1989 Quebec event as the basis for the 1 in 100 year storm is too severe, given the few “high magnitude” events that have occurred over the last 21 years, and therefore we believe that the requirements to provide mitigation for these extreme GMD events are not supported. On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Minnesota as for Louisiana, while conservative, we believe would be absurd. Consideration with respect to unique geographical differences must be maintained among the functional entities to whom this standard would be applicable, particularly for PC’s and their associated TP/TO entities.
Response: The benchmark GMD event is 2 to 2.5 times the March 1989 event, not 4-5 times. That said, the SDT needed to select a technically defensible electric field benchmark that was sufficiently conservative to encompass expected severe events without taking an event that was highly improbable. The 1 in 100 years probability appeared to the SDT to be a reasonable choice for the benchmark. The SDT continues to believe that the Pulkinnen et al statistical analysis provides the best analysis to address the above need. Regarding the issue of geomagnetic scaling, the SDT agrees that to model a transmission network that spans more than one degree of geomagnetic latitude with the highest alpha value would be very conservative. Commercial software allows users to use different V/km (and thus alpha factors and earth models) in different parts of the network.		
Texas Reliability Entity	No	1. Requirement R3: Texas Reliability Entity, Inc. (Texas RE) requests the SDT consider and respond to the concern that GMD criteria in the proposed standard

Organization	Yes or No	Question 1 Comment
		for steady state voltage performance is different than the steady state voltage performance criteria in other TPL standards or the SOL methodology. GMD events will typically not be transient in nature so adopting the steady state approach is preferable as it would simplify the studies if the voltage criteria between GMD events and other planning events were the same. 2. Requirement R7: Texas RE intends to vote negative on this proposed standard solely on the basis that we remain unconvinced that the proposed standard meets the intent of FERC Order 779. Paragraph 79 for the following reasons: (A) Reliance on the definition of Corrective Action Plans (CAP) in the NERC Glossary in lieu of including language in the requirement appears insufficient to address the FERC statement that a Reliability Standard require owners and operators of the BPS to “develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event.” While Texas RE agrees that requiring the development of a CAP in Requirement R7 meets part of the FERC directive, R7 falls short as there is no language in the requirement (and therefore the standard) that addresses completion of the CAP. The CAP definition calls for an associated timetable but does not address completion. Coupled with the language in R7.2, that the CAP be reviewed in subsequent GMD Vulnerability Assessments, it is conceivable that a CAP may never get completed as timetables can be revised and extended as long as the deficiency is addressed in future Vulnerability Assessments. Without a completion requirement, a demonstrable reliability risk to the BES may persist in perpetuity. Texas RE recommends the SDT revise Requirement R7.2 as follows: “Be completed prior to the next GMD Vulnerability Assessments unless granted an extension by the Planning Coordinator.” (B) The language in R7.1 does not appear to adequately address the FERC statement that “Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting

Organization	Yes or No	Question 1 Comment
		against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." While R7.1 lists examples of actions needed to achieve required System performance, it does not expressly restrict a CAP from only including revision of operating procedures or training. In addition, Table 1 language regarding planned system adjustments such as transmission configuration changes and redispatch of generation, or the reliance on manual load shed, seem to contradict the FERC language regarding the limiting plans to considering operational procedures. Texas RE suggests the revising the language of R7.1 as follows: "Corrective actions shall not be limited to considering operational procedures or enhanced training, but may include:" Alternatively, Texas RE suggests the addition of language to the Application Guidelines for Requirement R7 reinforcing FERC's concern that CAPs "must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." 3. Compliance Monitoring Process Section: Evidence RetentionTexas RE remains concerned about the evidence retention period of five years for the entire standard. (A) Texas RE reiterates the recommendation that the CAP should be retained until it is completed. The SDT responded to Texas RE's first such recommendation with the following response: "The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance."With a periodic study period of five years, a CAP may extend significantly beyond the five-year window, especially in cases where equipment replacement or retrofit may be required. A retention period of five years could make it difficult to demonstrate compliance and could

Organization	Yes or No	Question 1 Comment
		potentially place a burden on the entity as they will be asked to "provide other evidence to show that it was compliant for the full time period since the last audit." Texas RE recommends the SDT revise the retention language to state responsible entities shall retain evidence on CAPs until completion. (B) Texas RE also recommends revising the evidence retention to cover the period of two GMDVAs. The limited evidence retention period has an impact on determination of VSLs, and therefore assessment of penalty. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained.
Response: 1. The statement regarding steady state voltage requirements was included in the standard to provide the flexibility that the steady state voltage requirements may be less conservative than those requirements for the ongoing reliability analyses required by TPL-001. The requirement is not intended to prohibit a planning entity from using criteria that are the same as TPL-001. 2. The standard does require the preparation of a Corrective Action Plan (CAP) for situations where the Benchmark GMD conditions cannot be met. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction. 3. The SDT agrees with the comment regarding evidence retention and has edited the standard to modify the requirements regarding evidence retention.		
Pepco Holdings Inc.	No	See Comments on items 2 and 4
Omaha Public Power District	No	The Omaha Public Power District (OPPD) is concerned with language in "Table 1 - Steady State Planning Events" that requires entities to perform steady state planning assessments based on "Protection System operation or Misoperation due to harmonics during the GMD event". The Planning Application Guide's

Organization	Yes or No	Question 1 Comment
		Sections 4.2 and 4.3 specifically mention the unavailability of tools and difficulty in performing an accurate harmonic assessment but does not provide resolution or recommendation on how to accurately address the concern. The statement from Section 4-3 is referenced below. "The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results."Additionally, there needs to be a clearer definition of how the steady state planning analysis due to GMD event harmonics is to be performed. Is it the intent of the standard to study the removal of all impacted Transmission Facilities and Reactive Power compensation devices simultaneously, sequentially, or individually as a result of Protection operation or Misoperation due to harmonics? The Planning Application Guide references the "NERC Transformer Modeling Guide" in several places as a reference for more information on how to perform the study. The "NERC Transformer Modeling Guide" is shown in the citations as still forthcoming. OPPD doesn't believe this standard should be approved prior to the industry seeing the aforementioned transformer modeling guide. Further, OPPD does not believe it is feasible to implement a full harmonic analysis in the implementation timeframe for TPL-007. In a very broad view, the standard requires a specific analysis that the industry doesn't have the skill set or tools to perform. This is acknowledged by the supporting documents. The reference document cited as a resource to further explain how to perform the studies has not been created yet.

Response: The SDT acknowledges that harmonics analysis is a technical specialty and comprehensive harmonics analysis tools and capability are not in wide availability in the industry. However, the SDT believes that some basic harmonics knowledge can be applied in the GMD Vulnerability Assessment process and is necessary to address this reliability risk. Using the available guidance, the planning entities should be able to make some decisions on specific equipment that may be compromised by harmonic currents and

Organization	Yes or No	Question 1 Comment
thus may be outaged in the network without conducting a harmonics analysis. FERC Order No. 779 specifies that the vulnerability assessments must account for the effects of "harmonics not present during normal BPS operation." The SDT will recommend to NERC technical committees that additional guidance be developed.		
Manitoba Hydro	No	Note "System steady state voltages shall..." was removed from Table 1, which removes the link back to requirement R3. Note d should be re-established and the language similar to that used in TPL-001-4 should be considered: "System steady state and post-Contingency voltage performance shall be within the criteria established by the Planning Coordinator and the Transmission Planner."
Response: The objective of the GMD Vulnerability Assessment is to prevent, voltage collapse, cascading, and uncontrolled islanding. Voltage performance as it pertains to the prevention of the conditions above applies.		
City of Tallahassee	No	Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: The impact of a geomagnetic induced current (GIC) on a TO's system is greatly dependent on the geomagnetic latitude and the earth conductivity below an applicable TO's transformer. In the supporting documentation that the Standard Drafting Team (SDT) has provided during the balloting process, there has been zero evidence indicating that a transformer has ever been detrimentally affected that lies in the low latitude United States, e.g., Florida/FRCC Region. Additionally, the SDT has failed to produce earth conductivity information that is specific for the FRCC Region.
Response: The proposed standard is responsive to FERC directives for development of standards for the assessment of GMD impacts on BPS equipment and the BPS as a whole. Historical records may not reveal low-latitude impacts in North America. The benchmark is of a 100-year magnitude which may result in low-latitude impacts. Geomagnetic latitude and earth structure are taken into account in the GMD Vulnerability Assessment process.		

Organization	Yes or No	Question 1 Comment
South Carolina Electric & Gas	No	On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such having the same geomagnetic scaling factor for a footprint that covers a wide variety of latitudes and bedrock conditions. The individual the applicable entities should be allowed to use judgment in applying the scaling factors.
Response: The standard provides the flexibility to "perform analysis using a non-uniform or piecewise uniform geomagnetic field." This means using different scaling factors in regions with significantly different alpha factors. Entities are given the flexibility to use technically-justified scaling factors other than the maximum.		
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp.	Yes	
MRO NERC Standards Review Forum MidAmerican Energy Company	Yes	The NSRF agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Response: See Question 2.		
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Associated Electric Cooperative, Inc.	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	
Idaho Power	Yes	
Exelon	Yes	
Hydro-Quebec TransEnergie	Yes	
ISO New England	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
ReliabiltiyFirst	Yes	ReliabilityFirst votes in the Affirmative and believes the TPL-007-1 standard enhances reliability and establishes requirements for Transmission system

Organization	Yes or No	Question 1 Comment
		planned performance during geomagnetic disturbance (GMD) events. ReliabilityFirst offers the following comments for consideration. 1. Requirement R7 - During the last comment period ReliabilityFirst provided a comment on Requirement R7 which suggested that R7 should require the Entity to not only develop a Corrective Action Plan but “Implement” it as well. The SDT responded with “CAP must include a timetable for implementation as defined in the NERC Glossary”. Even though the NERC definition of CAP implies that an entity needs to implement the CAP, ReliabilityFirst does not believe it goes far enough from a compliance perspective. ReliabilityFirst also notes that other NERC/FERC approved standards (PRC-004-2.1a R1 - “...shall develop and implement a Corrective Action Plan to avoid future Misoperations...” and PRC-004-3 - R6 “Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5...”) require entities to “Implement the CAP” so ReliabilityFirst believes it is appropriate to in include this language. ReliabilityFirst offers the following language for consideration: “Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall:”
Response: The SDT does not support the proposed change to Requirement R7. As with other TPL standards, it is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction.		
Tri-State Generation and Transmission Association, Inc.	Yes	Although Tri-State appreciates the intent of the language change in R3, we believe it's now ambiguous as to what is meant by "performance." What did the SDT have in mind with that change? How does the SDT imagine this to be audited?Tri-State believes there is an error in Attachment 1 of the standard. On page 11 under "Scaling the Geoelectric Field" it reads: "When a ground

Organization	Yes or No	Question 1 Comment
		conductivity model is not available the planning entity should use the largest Beta factor of physiographic regions or a technically justified value." However on page 22 of the GMD Benchmark White Paper under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use a Beta Factor of 1 or other technically justified value." These should be consistent and the Attachment in the standard should read as it does in the Benchmark White Paper. There is language already stating that the largest Beta Factor of 1 should be used in cases where entities have large planning areas that span more than one physiographic region.
Response: The SDT believes Requirement R3 provides the necessary obligation for the planning entity to establish performance criteria without prescribing a specific approach. Voltage limits could satisfy this requirement. A rationale box has been added to clarify the SDT intent. Page 22 of the Benchmark GMD Event description has been corrected to be consistent with Attachment 1.		
PJM Interconnection	Yes	
Oncor Electric	Yes	
California ISO		The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

2. **Implementation. The SDT has revised the proposed Implementation Plan from an overall four-year implementation to five years based on stakeholder comments. Do you agree with the changes made to the Implementation Plan? If not, please provide a specific recommendation and justification.**

Summary Consideration: The SDT thanks all who commented. The SDT is not proposing any changes to the implementation plan. However a significant concern with implementation is being addressed through the revisions to the Transformer Thermal Impact Assessment white paper and the revised screening criterion. Specific responses to other comments follow:

- **Timelines for R4 & R5 may not coincide properly and 12 months for developing Corrective Action Plans is insufficient**. The SDT recognized the iterative nature of the GMD Vulnerability Process as depicted in the Application Guidelines section. A summary of implementation is provided (dates reference approval by regulatory authority):
    - 6 months - R1 (Responsibilities)
    - 18 months - R2 (System models)
    - 24 months - R5 (GIC flow information)
    - 48 months - R6 (Thermal Assessment)
    - 60 months - R3 (Performance criterial), R4 (GMD VA), and R7 (CAP).
- **Regarding the data validation and model assumptions for the GMD Vulnerability Assessment and the transformer thermal impact assessment**, the standard allows the use of technically justified earth models or transformer generic models. Technical justification could take the form of updates from USGS and NRCan, as well as adjustments on the basis of concurrent GIC and geomagnetic field measurements.
- **Timeline for coordination and data verification**. **A commenter stated that the time needed to coordinate with neighbors to finalize their models.** The SDT expected the coordination efforts among interconnecting entities in developing system models within the 24-months implementation timeframe. This GMD impact assessment and coordination process is in line with the existing planning process to address any system deficiency issues, and the existing planning coordination mechanism among stakeholders and best practices are expected to apply to the GMD impact assessment process.

- **Tools availability. A commenter stated that GMD Tools are missing**. The revised transformer thermal assessment whitepaper addresses concerns by providing a readily available assessment approach. Also, GMD tools (Geoelectric Field Calculator and Thermal Assessment Tool) developed by Hydro One were provided to facilitate the GMD Vulnerability Assessment and the transformer thermal impact assessment. Available at: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Planning-Tools.aspx

Organization	Yes or No	Question 2 Comment
Colorado Springs Utilities	No	1.) As many companies are going to be required to buy software and train for the specific modeling being required we recommend that this requirement have a 24 month implementation period. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: Based on the other industry comments and the SDT's experience the implementation period for R2 is maintained at 24-calendar months after the effective date of the standard.		
Florida Municipal Power Agency FRCC GMD Task Force	No	FMPA supports the comments of the FRCC GMD Task Force (copied below).The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of ‘priliminary’ with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force recommends insertion of the following language into the Implementation Plan after the paragraph describing the implementation of R2 and prior to the paragraph describing the implementation of

Organization	Yes or No	Question 2 Comment
		R5: "Implementation of the remaining requirements (R3 - R7) will be delayed for the FRCC Region pending resolution of the inconsistencies associated with Regional Resistivity Models developed by the USGS. Once the conductivity analysis is completed and appropriate scaling factors can be determined for the peninsular Florida 'benchmark event', the FRCC Region will implement the remaining requirements from the date of 'published revised scaling factors for peninsular Florida' per the established timeline." This delay will provide a level of certainty associated with the results of the GMD Vulnerability Assessments and Thermal Impact Studies conducted in the FRCC Region, thus establishing a valid foundation for the determination of the need for mitigation/corrective action plans.
Response: The ground model for Florida has been provided. USGS is in the process of updating their website. The standard allows the use of updated models at any time as specified in Attachment 1.		
Duke Energy	No	Based upon our review of the Implementation Plan, it appears that the proposed timelines for some of the requirements (specifically R4 & R5) may not coincide properly. We request further explanation of the timelines, and their relationships between the various requirements.
Response: Timelines in R4 and R5 support the overall GMD VA process as depicted in the application guideline. Details have been provided in the rationale boxes of the standard to clarify the sequencing.		
Associated Electric Cooperative, Inc.	No	AECI appreciates the SDT's acceptance of additional time for transformer thermal assessments, however it is still difficult to estimate the time required to complete these assessments when two major pieces are missing (the transformer modeling guide and thermal assessment tool). Although it has been stated these will be available soon, there may be unforeseen issues in utilizing the tool or the results produced, which may require a significant amount of time to address. AECI requests language in the implementation plan to include an allowance for extension if completion of these tools under development are significantly delayed. Additionally,

Organization	Yes or No	Question 2 Comment
		AECI anticipates issues with meeting deadlines for DC modeling and analysis. Although 14 months for preparation of DC models internal to the AECI system seems reasonable, AECI's densely interconnected transmission system (approximately 200 ties internal and external to our system) may create timing issues when considering the coordination of models with neighboring entities. Our neighbors will be able to finalize their models on the 14 month deadline, leaving no time for coordination and verification of their data. AECI would request or the addition of a milestone for internal completion at 14 months, and an additional 6 months for coordination and verification with neighbors.
Response: The revised standard and thermal impact assessment white paper address the model availability concern. The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method for transformers which can be used for a conservative assessment of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. The SDT did not support adding a specific milestone for coordination of models with neighboring entities. This could be part of a planner's input to the coordination of responsibilities with the PC that must occur in Requirement R1. Regardless, the team believes that an entity will be able to have models of their planning area within 18 months of the effective date of the standard.		
IRC SRC California ISO	No	Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised.

Organization	Yes or No	Question 2 Comment
Response: Implementation times are coordinated to be consistent with the GMD VA process as depicted in the Application Guidelines section. The implementation plan establishes the required completion date. In order to complete the GMD VA, the planner must have the thermal assessment information from the equipment owners.		
ACES Standards Collaborators	No	We appreciate the SDT's recognition that the previous implementation plan identified for this standard was too short and burdensome for entities. More time and information need to be made available for entities to properly construct the necessary data models and conduct these new studies correctly. Entities have also received limited assistance with their vendors on the provision of the data necessary to conduct these studies. Large and small entities have limited resources, software, and industry knowledge in this area. Moreover, for smaller entities with limited staff and financial resources, this effort will be a significant challenge. We continue to recommend that the implementation period be extended to eight years to allow industry an opportunity to fully engage in this effort.
Response: Based on the majority of stakeholder feedback and the SDTs experience the implementation plan is maintained at 5 years.		
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: See question 1.		
Volkmann COnsulting	No	There is no technical justification to add an additional year to the process to an imminent problem
Response: The SDT consider the comments of stakeholders and their own experience and is maintaining the 5-year implementation plan.		
Concerned citizen	No	Given the studies that I referenced in my response to Question 1, four years may be too long.

Organization	Yes or No	Question 2 Comment
Response: The SDT consider the comments of stakeholders and their own experience and is maintaining the 5-year implementation plan.		
Pepco Holdings Inc.	No	: Screening models are not developed so this requirement puts the cart before the horse and the revised standard just proposes to move the due date out .
Response: The revised standard and thermal impact assessment white paper address the model availability concern. The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a generic thermal model for transformers which can be used for a conservative assessment of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.		
ISO New England	No	We agree with extending the implementation plan to 60 months. However, more time for the development of the Corrective Action Plan under Requirement R7 should be provided within those 60 months. Once a Corrective Action Plan for one transformer is developed, the entity responsible for developing the Corrective Action Plan will have to run the model again to determine whether another Corrective Action Plan for other transformers is needed as a result of the first Corrective Action Plan. This step may have to be repeated several times. Thus, the time that the entities responsible for developing Corrective Action Plans have from the time they receive the results of the thermal impact assessments under Requirement R6 (which under the current timeline is only 12 months) is insufficient. Accordingly, we strongly suggest that the time for implementation of Requirement R6 be changed from 48 months to 42 months. The time for implementation for Requirement R7 would remain at 60 months but responsible entities would have 18 months to develop the Corrective Action Plans.

Organization	Yes or No	Question 2 Comment
Response: Stakeholder feedback has strongly indicated the need for 48 months to complete R6. The SDT recognizes the challenge of transformer modeling and supports this position. Based on SDT experience and response from most stakeholders, Requirement R7 can be met within 60 months of the effective date of the standard.		
Omaha Public Power District	No	Please refer to comments in Question 1.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp.	Yes	Increase from 4 to 5 years is an improvement
MRO NERC Standards Review Forum MidAmerican Energy Company	Yes	1. The NSRF agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. We suggest the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement: The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.

Organization	Yes or No	Question 2 Comment
Response: Effective dates in the implementation plan are sequenced to align with the Requirements. Requirement R5 is effective 24 months after the standard's effective date. Because Requirement R6 will become effective 48 months after the standards effective date, the applicable TO and GO has 24 months to complete the assessment as specified in part 6.4.		
SERC Planning Standards Subcommittee	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
SPP Standards Review Group	Yes	Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requirements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
Seattle City Light	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Foundation for Resilient Societies	Yes	With a 60 month implementaiton period, it would be highly beneficial to utilize and require data sharing for the 104 or more GIC monitors now operational in the United States. See Foundation's "Additional Facts" filing in FERC Docket RM14-1-000 of Aug 18, 2014. A model using all the GIC monitors operating now or in the future would enable more cost-effective operating procedures and hardware protection decisions.
Response: GIC measurements are a means to validate and/or adjust earth models. The modelling approach proposed by Kappenman et al is only valid for the system configuration at the time of the measurements. Furthermore, the calibration and accuracy of GIC monitors, especially in the case of low magnitude events is an important consideration that has not yet been addressed at this point in time.		

Organization	Yes or No	Question 2 Comment
PacifiCorp	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	
Ameren	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Idaho Power	Yes	
Texas Reliability Entity	Yes	
Luminant Generation Company, LLC	Yes	
Exelon	Yes	
Hydro-Quebec TransEnergie	Yes	
City of Tallahassee	Yes	
Independent Electricity System Operator	Yes	
City of Tallahassee	Yes	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
South Carolina Electric & Gas	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Kansas City Power and Light	Yes	Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requiements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
Tri-State Generation and Transmission Association, Inc.	Yes	
PJM Interconnection	Yes	
Oncor Electric	Yes	
California ISO		The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

3. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for TPL-007-1? If you do not agree, please explain why and provide recommended changes**

Summary Consideration: The SDT thanks all commenters for their feedback on the proposed VRFs and VSLs. Specific responses are below:

- **Commenters did not agree that Requirements R4 and R7 met criteria for a VRF of "high".** They stated that failure to meet these requirements would not directly cause or contribute to BES instability, separation, or Cascading. The SDT finds that proposed requirements meet the criteria for "high" because failure to carry out the actions in these requirements could place the BES at an unacceptable risk of instability, separation, or cascading in a 100-year GMD event. In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred.
- **Commenters did not agree with VSL of "Severe" in Requirement R1 and Requirement R3.** The VSLs are consistent with NERC guidelines which specify that a VSL of "Severe" is appropriate when the requirement does not have any elements or quantities which can be used to evaluate degrees of compliance.

In the revised draft TPL-007-1, the Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). This filing responds to FERC Order No. 786 dated October 17, 2013.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	The NSRF suggest the SDT change the VSL row for Requirement R6 to match the words in the standard.Suggestion:"The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months..." The NSRF suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row.Suggestion:

Organization	Yes or No	Question 3 Comment
		"The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Response: The recommended changes have been made.		
SPP Standards Review Group Kansas City Power and Light	No	Generic - When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.R5 - Capitalize 'Parts 5.1 and 5.2' in the High and Severe VSLs for Requirement R5.R6 - Capitalize 'Part 5.1' and 'Parts 6.1 through 6.4' in the VSLs for Requirement R6.R7 - Capitalize 'Parts 7.1 through 7.3' in the Moderate, High and Severe VSL for Requirment R7.
Response: The recommended format for calendar periods is not in accordance with guidelines in use for consistency. Other recommended changes were made.		
Florida Municipal Power Agency	No	FMPA does not agree with the SDT that failure to meet R4 or R7 could DIRECTLY cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures during a 1-in-100 year GMD event, and continues to believe the VRFs for these requirements should be lowered to medium.
Response: The SDT believes that proposed requirements meet the criteria for "high" because failure to carry out the actions in these requirements could place the BES at an unacceptable risk of instability, separation, or cascading in a 100-year GMD event. In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred.		
IRC SRC California ISO	No	1. Requirement R1 is a purely administrative requirement and, while important to ensure that all requirements are fully satisfied, should not be assigned a "Severe" VSL. A Moderate VSL is proposed.

Organization	Yes or No	Question 3 Comment
		2. Requirement R3 is a purely administrative requirement and, while important to ensure that system performance criteria are documented and understood, should not be assigned a “Severe” VSL. A Moderate VSL is proposed. 3. The VSL assigned to Requirement R2 penalizes the responsible entity for not maintaining “System model”, which is already a requirement in MOD-032-1, R1. Assuming “GIC System model” includes “DC Network models” the VSL language assigned to Requirement R2 should be modified as follows: “The responsible entity did not maintain GIC System models of the responsible entity’s planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).”
Response: NERC and FERC VSL guidelines specify that requirements which cannot be assessed incrementally or via degrees must use VSL of "Severe".		
ACES Standards Collaborators	No	We appreciate the SDT’s efforts to identify measureable criteria for many of the VSLs identified in this standard. However, we continue to disagree with the SDT’s assignment of VRFs for this standard. The SDT identifies that they have aligned the VRFs with the criteria established by NERC. However, we want to remind the SDT of the planning horizon identified in this standard and not to confuse the nature of the event with insufficient or unsupported GMD Vulnerability and thermal impact assessments. We disagree with the categorization of Medium VRFs for the applicable requirements because these requirements could not “under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.” While the nature of the event could affect the electrical state or capability of the BES, we believe not maintaining system models or identifying performance criteria for acceptable system steady state voltage limits would have no affect on the electrical state or capability of the BES.

Organization	Yes or No	Question 3 Comment
Response: In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred. VRF for Requirement R2 is consistent with other planning standards, NERC guidelines, and FERC's recent orders that affirm VRFs for modeling requirements that are needed for planning.		
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Seminole Electric Cooperative, Inc.	No	See Comments for #1 above and previous ballot Comments.
MidAmerican Energy Company	No	MidAmerican suggest the SDT change the VSL row for Requirement R6 to match the words in the standard.Suggestion:”The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months...”MidAmerican suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row.Suggestion:”The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Response: The suggested edits were made.		
Arizona Public Service Company	Yes	
Dominion	Yes	

Organization	Yes or No	Question 3 Comment
Colorado Springs Utilities	Yes	We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
FirstEnergy Corp.	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	
Associated Electric Cooperative, Inc.	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Foundation for Resilient Societies	Yes	
American Electric Power	Yes	
Volkmann COnsulting	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 3 Comment
Ameren	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	
Pepco Holdings Inc.	Yes	
Exelon	Yes	
ISO New England	Yes	
City of Tallahassee	Yes	
Omaha Public Power District	Yes	
City of Tallahassee	Yes	
Manitoba Hydro	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 3 Comment
Oncor Electric	Yes	

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

Summary Consideration: The SDT thanks all commenters. Several editorial changes were made throughout the standard.

Modeling Requirements. The SDT believes that MOD-032 provides the necessary means for planning entities to obtain modeling data for GMD Vulnerability Assessments (GMD VA). TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes. Future revisions of MOD-032 should be updated to maintain a single modeling standard.

Regional Cost-Benefit analysis. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require less effort and cost for transformer thermal assessments due to enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives.

Benchmark GMD Event. Specific responses to the various comments are below.

Comparison to Cat D or Cat C from TPL standards. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events.

Specific responses are below:

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
Dominion	No	
FirstEnergy Corp.	No	

Organization	Yes or No	Question 4 Comment
Duke Energy	No	
Associated Electric Cooperative, Inc.	No	
ACES Standards Collaborators	No	(1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. Thank you for the opportunity to comment.
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: The proposed standard addresses potential wide-area impact caused by a rare GMD event. It is responsive to the Standards Authorization Request and FERC directives.		
Tacoma Power	No	
American Transmission Company, LLC	No	
Texas Reliability Entity	No	
Omaha Public Power District	No	
PJM Interconnection	No	
Oncor Electric	No	
Northeast Power Coordinating Council	Yes	1. The requirements and measures should be revised to allow Planning Coordinators to generally utilize consensus processes and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, the modeling data itself will need to come from the applicable

Organization	Yes or No	Question 4 Comment
		Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since those standards deal with load flow, stability, and short circuit data. Recommend that MOD-32 requirements R2 and R3 be added as requirements in the beginning of the GMD standard, but in R2 substitute the word “GMD” for “steady-state, dynamics, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. The Applicability section would have to be revised to include the additional entities. 2. Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read “...wye-grounded winding with voltage terminals operated at 200kV or higher”. 3. In Requirement R4 sub-Part 4.1.1. “System On-Peak Load” should be re-stated as “System On-Peak Load with the largest VAR consumption”. 4. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x Î± x Î² (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of

Organization	Yes or No	Question 4 Comment
		"antenna" effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections.This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.

Response: The SDT believes that MOD-032 provides the necessary means for planning entities to obtain modeling data for GMD Vulnerability Assessments (GMD VA). TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes.

2. Terminal voltage describes line-to-line voltage. The rationale box includes the recommended clarification.

3. By use of the defined term, the SDT is providing a clear requirement that is consistent with TPL-001. The suggested change is also correct but more difficult to determine ahead of time. The existing wording of Requirement R4 part 4.2.2 has been maintained.

4. The suggested changes to the application guide are not accurate. For uniform fields it is ok to model the system with dc sources connected to ground. However, the appropriate way to model non-uniform fields is with voltage source across the line. Refer to: Boteler, D.H.; Pirjola, R.J., "Modelling geomagnetically induced currents produced by realistic and uniform electric fields," *Power Delivery, IEEE Transactions on* , vol.13, no.4, pp.1303,1308, Oct 1998

Organization	Yes or No	Question 4 Comment
Con Edison, Inc.	Yes	1. FAC-003 avoids using the phrase “terminal voltage” by using the phrase “operated at 200kV or higher.” Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read “...wye-grounded winding with voltage terminals operated at 200kV or higher”. 2. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x Î± x Î² (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of “antenna” effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections.This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving

Organization	Yes or No	Question 4 Comment
		DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase.Any other figures with similar oversimplifications should also be changed to avoid confusion
Response: 1. Terminal voltage describes line-to-line voltage. The rationale box includes the recommended clarification. 2. The suggested changes to the application guide are not accurate. For uniform fields it is ok to model the system with dc sources connected to ground. However, the appropriate way to model non-uniform fields is with voltage source across the line. Refer to: Boteler, D.H.; Pirjola, R.J., "Modelling geomagnetically induced currents produced by realistic and uniform electric fields," *Power Delivery, IEEE Transactions on* , vol.13, no.4, pp.1303,1308, Oct 1998		
Colorado Springs Utilities	Yes	Thank you for all of your work on this - this is not an easy one! We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. On some of even the most recent calls there still appears to be some lack of understanding as technical questions are asked. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. We recommend a pilot program. Understandably the pilots would need to be expedited much like the CIP version 5 standards. With a pilot vetting the process and providing better guidance we could shorten the implementation plan to make-up time expended during pilots and best utilize industry resources. If we pilot the process and shorten the implementation period then the final implementation of the solution could be the same with a much better effect. Please ask the question on the pilot even if the standard must move forward as is. Having the regions and NERC work through the process quickly with a few entities would still be very beneficial. Then all the other

Organization	Yes or No	Question 4 Comment
		companies do not have to repeat the same mistakes to get where we really need to be. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: Field tests are governed by Section 6 of the Standards Process Manual (SPM). As described, these programs are conducted prior to formal comment periods to inform the standard development effort. SDT members have collectively conducted multiple GMD studies in many regions and applied their expertise to the development of the requirements and implementation plan.		
MRO NERC Standards Review Forum MidAmerican Energy	Yes	1. Page 9, Table 1 -Steady State Planning Events. The NSRF suggest that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, we suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. 2. Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion:4.2. Facilities:4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.4.2.1 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
Response: 1. Capabilities for assessing the impact of harmonics may vary by planning entity, however these impacts must be considered in a GMD Vulnerability Assessment. General considerations are provided in the GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012. One example of a justifiable approach is based on Section 4.2 of the GMD Planning Guide which states: *SVCs may trip if excessive harmonic current and voltage distortion cause intentional protective relay operation, excessive interactions with the SVC control system, or due to protection misoperation (false tripping) due to vulnerabilities of the protection system.* Since older style electro-mechanical relays are more		

Organization	Yes or No	Question 4 Comment
susceptible to tripping on harmonics, a planner could remove some or all SVCs that are protected by electro-mechanical relays and evaluate System performance. 2. The applicability section is correct for describing the necessary Facilities for this standard. Only Requirements related to thermal assessments (R5 and R6) are specifically limited to BES power transformers.		
SERC Planning Standards Subcommittee	Yes	In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The Transformer Modeling Guide is being developed by the NERC GMD TF in the GMD TF Phase II project plan approved by the Planning Committee. Currently commercial GIC software packages include default Reactive Power loss models.		
SPP Standards Review Group	Yes	We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics - Capitalize 'Reactive Power' in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics - Replace 'Wide Area' in the 1st line of the 6th bullet under General Characteristics. The lower case 'wide-area' was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term 'Wide Area' refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don't believe the usage here is restricted to an RC's Wide Area view. The lower case'wide-

Organization	Yes or No	Question 4 Comment
		area' is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude - In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the 'GIC system model'. In Requirement R2 of the standard a similar reference is made to the 'GIC System model' as well as 'System models'. In the later 'System' was capitalized. Should it be capitalized in this reference also? Statistical Considerations - In the 6th line of the 2nd paragraph under Statistical Considerations, insert 'the' between 'for' and 'Carrington'. Statistical Considerations - In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase '1 in 100 year' is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as '1-in-100'. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification - In the 3rd line of the 1st paragraph under the Justification section, the phrase '15 Amperes per phase neutral current' appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as '15 Amperes per phase'. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification - In the 2nd paragraph under the Justification section, the term 'hot spot' appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background

Organization	Yes or No	Question 4 Comment
		section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn't. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification - In the 4th line of the Figure 4 paragraph, '10 A/phase' appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Response: The recommended edits have been made.		
Florida Municipal Power Agency	Yes	FMPA supports the comments of the FRCC GMD Task Force (copied below).The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; "The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies." The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources.
Response: Thank you for your comments, your participation in the standard development process is appreciated. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require		

Organization	Yes or No	Question 4 Comment
fewer man hours and less cost for transformer thermal assessments due enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
FRCC GMD Task Force JEA	Yes	The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC GMD Task Force requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; “The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies.” The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources.It has become very apparent that the SDT and NERC staff are unwilling to analyze the cost for implementation of this Standard, therefore, the FRCC GMD Task Force continues to request that the SDT perform a CEAP and specifically that the CEAP take into consideration the geological differences that are material to this standard, i.e., latitude. The CEAP process allows for consideration and comparison of all implementation and maintenance costs. In addition, the process allows for alternative compliance measures to be analyzed, something that may benefit those Regions where the reliability impact may be low or non-existent, i.e., lower latitude

Organization	Yes or No	Question 4 Comment
		entities. In support of this request the FRCC GMD Task Force would like the SDT to consider the NARUC (National Association of Regulatory Utility Commissioners) resolution, "Resolution Requesting Ongoing Consideration of Costs and Benefits in the Standards development process for Electric Reliability Standards" approved by the NARUC Board of Directors July 16, 2014, which can be provided upon request.
Response: The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require less effort and cost for transformer thermal assessments due enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
City of Tallahassee	Yes	It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. The impact of a geomagnetic induced current (GIC) on a TO's system is greatly dependent on the geomagnetic latitude and the earth conductivity below an applicable TO's transformer. In the supporting documentation that the Standard Drafting Team (SDT) has provided during the balloting process, there has been zero evidence indicating that a transformer has ever been detrimentally affected that lies in the low latitude United States, e.g., Florida/FRCC Region. Additionally, the SDT has failed to produce earth conductivity information that is specific for the FRCC Region.

Organization	Yes or No	Question 4 Comment
Response: The proposed benchmark has been developed by SDT members with relevant research and engineering experience. Technical justification has been provided as specified in the project SAR and FERC directives. Peer review is not in the project scope per the SAR, however the analysis has been submitted to a technical journal and is undergoing peer review. Low-latitude impacts have not been recorded however the 100-year benchmark GMD event is more severe than recent events and could potentially cause impacts. The proposed standard accounts for geomagnetic latitude and earth conductivity in the assessments. The Florida ground model has been researched by USGS. Like the other models described in the proposed standard and white paper it is based on available geological literature.		
Seattle City Light	Yes	Seattle City Light is concerned with the effectiveness of the proposed approach (considerations of scientific and engineering understanding aside). Seattle is a medium-small vertically integrated utility, and like many such entities, is registered as a Planning Coordinator and Transmission Planner for our system and our system alone. And like many similar entities, we are closely connected with a large regional transmission utility (Bonneville Power Administration in our case). For this type of arrangement a GMD Vulnerability Assessment performed by Seattle (acting alone) on Seattle's own system (considered alone) will be of little or no value. GMD assessments by other, similarly situated entities likewise will have little or no value. Recognizing the large number of such entities in WECC (something like half of the Planning Coordinators in all of NERC) and the Pacific Northwest, Seattle and others presently are coordinating with regional planning bodies in an effort to arrange some sort of common GMD Vulnerability Assessment that could promise results of real value across the local region. Aside from the usual difficulties attendant upon such an exercise in collaboration, the wording of Requirement R1 that assigns responsibility to Planning Coordinators individually introduces administrative compliance concerns that hinder coordination. Seattle asks that the Drafting Team consider alternative language for R1 (and Measure M1) that would more clearly allow, if not encourage, the possibility for local collaboration among Planning Coordinators. If such changes are not possible, a second best solution would be a paragraph in the guidance

Organization	Yes or No	Question 4 Comment
		documentation stating that collaboration among Planning Coordinators is considered to be a means of meeting compliance with R1.
Response: The proposed standard does not restrict such collaboration from occurring. The SDT agrees with the recommendation to include guidance in the rationale box for R1: *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		
Sacramento Municipal Utility District	Yes	We'd like to express our gratitude and acknowledge the SDT efforts in preparing this standard.We wish to encourage the standard drafting team to consider the flexibility for entities to meet the Requirement R1 through including regional planning groups or something equivalent in Requirement R1. This would allow an entity's participation in such planning groups to meet the terms of the requirement while providing a consistent study approach within a regional boundary. We believe this change meets FERC's intent while alleviating entities duplication of studies while providing a consistent approach on the regional basis.R1. Each Planning Coordinator "or regional planning group", in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). Thank you.Joe Tarantino, PE
Response: Response: The proposed standard does not restrict such collaboration from occurring. The SDT agrees with the recommendation to include guidance in the rationale box for R1: *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		

Organization	Yes or No	Question 4 Comment
IRC SRC California ISO	Yes	1. Table 1 states that Protection Systems may trip due to effects of harmonics and that the analysis shall consider removal of equipment that may be susceptible. Specifically, Table 1 provides:"Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event"However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess "Misoperation due to harmonics". The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked. 2. The SRC respectfully notes that this standard is unlike other NERC standards. While the SRC understands that the scope and assignment of the drafting team was to develop standards to implement mitigation of GMD events, the industry has little experience in the matter and, as a result, the proposed standard is a composition of requirements for having procedures and documentation of how an entity performs a GIC analysis for GMD, which essentially makes the overall standard administrative in nature. The SRC would submit to the SDT that this is not the best use of resources and, as these comments point out, are quite removed from direct impacts on reliability. At a minimum, none of the requirements within this standard deserve High VSL ratings. In fact, it is highly probable that, if these requirements were already in effect today, they would be clear candidates for retirement under FERC Paragraph 81. While SRC understands that these requirements are the most effective way to address GMD risk at this time, the compliance resources involved to meet these requirements need to be considered on an ongoing basis and future efforts must be made to evolve the standard into more performance and result-based requirements, which would facilitate the retirement of the procedural/administrative requirements that currently comprise this standard.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td colspan="3">Response: 1. The GMD Planning Guide and 2012 GMD TF Interim Report provide general considerations for the planner to use in a GMD Vulnerability Assessment (see GMD Planning Guide and Section 6 of NERC “Effects of Geomagnetic Disturbances on the Bulk Power System”, Interim Report, February 2012). The SDT does not believe that the state-of-the-art for harmonics analysis supports the recommended change.

2. The SDT developed the requirements in TPL-007 to meet NERC guidelines for quality. Development of a GMD Vulnerability Assessment and mitigating actions for a 100-year GMD event are results-based requirements.</td></tr>
<tr><td>Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana</td><td>Yes</td><td>Vectren proposes the SDT to consider a different approach to the Applicability and/or registered functions identified in R1. Consider modifying the Applicability section of TPL-007-1 to mirror CIP-014’s Applicability section; ‘Transmission Facilities that are operating ... 200 kV and ... above at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an ‘aggregated weighted value’ exceeding ### according the to the table (table to be created by SDT or to use the same from CIP-014). To identify the greatest threat to the Bulk Electric System (BES), the SDT could revise Requirement R1’s responsible registered functions to only the Planning Coordinator.

Vectren believes the PC performing a system-wide assessment would be of greater value to the BES over including entities with less of an overall reliability impact to the BES. Data to perform the assessment is provided to the Planning Coordinator as part of existing MOD, FAC, and PRC standards.</td></tr>
<tr><td colspan="3">Response: 1. The triggering event addressed by the CIP-014 standard is not the same as the wide-area nature of GMD events. The SDT is not convinced that wide-area impact of a benchmark GMD event can be assessed using this subset of transformers.

2. The standard provides the flexibility for the PC to carry out the studies or any other entity that may be in a better position to do so. It should be emphasized that asset managers (TO and GO, not the PC) are in the best position to make decisions on equipment that do not impact the reliability of the BES</td></tr>
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Organization	Yes or No	Question 4 Comment
Iberdrola USA	Yes	Direction on the scope of reactive devices to be removed in the standard's Table 1 should be provided. This would include number of devices and/or % within a geographic proximity. It is not clear whether all devices or only specified devices should be removed from service.
Consistent harmonics response		
Bonneville Power Administration	Yes	BPA notes that presently commercial study software does not have the functionality to evaluate the impact of GIC on a transformer; it needs to be capable of this in order to appropriately apply the screening criteria for the complexity of analyzing flows through a transmission network via a benchmark storm. The most significant need is for autotransformers as the core is exposed to an "effective current" influence for the actual flux saturation level which is from an additive or subtractive coupling of current flow in the common and series winding. BPA reiterates our question from the previous comment period: Table 1 "Category" column indicates GMD Event with Outages. Does this mean the steady state analysis must include contingencies? If so, what kind of contingencies: N-1, N-2, ...? If not, BPA requests clarification of the category of GMD Event with Outages.
Response: 1. The SDT agrees with comments on the limitations of commercial tools. TPL-007 requirements can be met with existing tools and techniques. 2. The Outages referred to under Category within Table 1 refer to the Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD Event. As written, it does not require contingency analysis, but does not prevent entities from taking a further step and doing such analyses		

Organization	Yes or No	Question 4 Comment
Idaho Power	Yes	Idaho Power System Planning comments that additional clarity needs added to Table 1 regarding the GMD Event with Outages Category.It is unclear if planners have to include contingency conditions during a GMD event in the vulnerability assessment. If intent of the SDT is to require contingency analysis during a GMD Event to assess system performance; the required contingency categories (i.e. A or N-0, B or N-1, C or N-2) should be clearly identified in Table 1.
Response: The Outages referred to under Category within Table 1 refer to the Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD Event. TPL-007 does not require contingency analysis, but does not prevent entities from taking a further step and doing such analyses		
Foundation for Resilient Societies	Yes	The Foundation for Resilient Societies submits these Comment 1 of 2, and separately. A second comment submitted on Oct 10 2014 involves graphics for concurrent GIC spikes at near-simultaneous times hundreds or even thousands of miles apart. These findings refute the unsubstantiated "GIC Hotspot" model used to average down the effective GIC levels. This bias, combines with the alpha modeling bias (See Kappenman-Radasky White Paper submitted on July 30, 2014) and the beta modeling bias (See Kappenman-Birnbach comments 10-10-2014) in combination result in the NERC GMD Benchmark Model under-estimating overall geoelectric fields and risks to critical equipment by as high as one order of magnitude. Unless corrected, cost-effective purchases of protective equipment will be needlessly discouraged, and the grid will remain at needless risk. ANSI standards and NERC's standards process manual require addressing flaws and criticisms on their merit. This has not been done!
Response: The drafting team has reviewed the supplemental comment and provides the following: 1. The benchmark is 8 V/km, not 5.77 V/km as written in the first paragraph of the supplemental comment. 2. The statistical analysis in the benchmark is used to determine the amplitude of extreme 100-year geoelectric fields. Magnetometers recordings from 1989 GMD event provide a conservative time-series to perform the thermal analysis. The		

Organization	Yes or No	Question 4 Comment
observation of “simultaneous GIC peaks” or “simultaneous dB/dt” has no relation with the proposed methodology to estimate the benchmark geolectric field amplitude (8 V/km). 3. The benchmark geolectric field (8 V/km) was developed using wide-area spatial averages, and therefore, by definition, the geoelectric field can, and does, extend over a wide area. Figure 1 is not in conflict with the methodology used to develop the standard. The local enhancement does not mean that in other regions the geoelectric field must be zero. Figure 1 shows the typical characteristics of the geoelectric field and it is not related to local enhancements. 4. It is not possible, and it can be quite misleading, to analyze Figure 1 without a power system model. However, if we neglected the effects of power system topology and network resistance (which we emphasize cannot be done), we notice that Rockport measured 80 Amps while Kammer measured only 40 Amps; i.e., half the GIC magnitude of Rockport. Similarly, Figure 3 shows that OTT measured more than twice the peak amplitude dBx/dt than STJ. This is precisely why the standard contemplates wide-area spatial averages to estimate extreme geoelectric fields. It would be incorrect to define a benchmark to be applied continent-wide when we observe significant differences across the system driven by geographic (latitude and ground conductivity), system characteristics, and near-space electric current systems.		
PacifiCorp	Yes	PacifiCorp is voting no on this ballot to reflect our concerns (a) that insufficient evidence has been presented to show that the potential impact of a geomagnetic disturbance is significant for the majority of the North American electrical grid, and (b) that the effort that will be required to fully comply with this standard as drafted is not commensurate with the risk. However, PacifiCorp would support this effort if the initial implementation was limited to areas with the highest levels of perceived risk such as areas, for example, above 50 degrees of geomagnetic latitude and within 1000 kilometers of the Atlantic or Pacific coasts. Based on this approach, methods and tools used for the assessment can be further developed while addressing those areas most at risk.PacifiCorp’s concerns can be summarized as follows:(1) The SDT had not provided adequate evidence to show that the impacts of Geomagnetic disturbance are significant at lower latitudes. (2) The at-risk areas for impacts on the transmission system due to Geomagnetic disturbance are limited. The SDT should consider applying this standard only to utilities above 60Â° geomagnetic latitude until adequate data and evidence is available to show lower latitude utilities are impacted to the same degree as higher latitude utilities. (3) In cases where an assessment is

Organization	Yes or No	Question 4 Comment
		deemed necessary, the SDT should consider adding a specific provision where the utilities will be allowed to use prior cycle study results unless a stronger solar storm has been detected than the test signal or significant changes have occurred in the transmission system. Such a provision will reduce the burden on utilities and their customers.
Response: The SDT has reviewed your comment. The SDT recognizes that risk varies with latitude and has developed the benchmark and standard to take this into account. The suggestion to limit applicability to utilities above 60 degree north latitude would not meet purpose of the proposed standard as outlined in the SAR. The revised TPL-007 has incorporated enhancements in the thermal assessment methods that will significantly reduce the effort needed to evaluate thermal impacts. The SDT has added language to the rationale box for R6 to indicate that basing a thermal assessment upon review of the prior thermal assessment is acceptable.		
University of Memphis	Yes	In Appendix I of the Benchmark Geomagnetic Disturbance Event Description, I was concerned to see a decision to compute geoelectric field amplitude statistics that are averaged over a wide area. Appendix I of the Benchmark GMD Event Description currently states "The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales... Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below" (p. 9). However, to prepare for GMDs via the benchmark's current method (averaging over a square area of approximately 500 km in width) is similar to anticipating a 7.0 earthquake somewhere along the California coast, but preparing only for the average expected impact. Because the earthquake is only expected in one particular location, the average impact across the entire coast will be miniscule; if all locations prepared only for the average impact, some would be woefully underprepared. In fact, the assumption is far worse than this earthquake analogy implies, because local failures in interconnected power systems can

Organization	Yes or No	Question 4 Comment
		and do produce wide-area effects, as seen during the 1989 Hydro-Quebec blackout and the Northeast blackout of 2003*. Thus, analyses based on localized spatial scale estimates are precisely what is relevant, not wide-area spatial averages. I am also concerned that the extreme value analysis described does not take into account the fact that extreme space weather events follow a power law distribution (Lu & Hamilton, 1991; Riley, 2012). As stated by Riley (2012), "It is worth emphasizing that power laws fall off much less rapidly than the more often encountered Gaussian distribution. Thus, extreme events following a power law tend to occur far more frequently than we might intuitively expect" (see also Newman, 2005). Therefore it is likely that the analysis substantially underestimates the risk of high geoelectric field amplitudes. *Though not related to GMDs, the Northeast blackout of 2003 is nonetheless a good example of a local failure having wide-area effects.Lu, E. T., and R. J. Hamilton (1991), Avalanches and the distribution of solar flares, Astrophys. J., 380, L89-L92.Newman, M. (2005), Power laws, Pareto distributions and Zipf's law, Contemp. Phys., 46, 323-351.Riley, P. (2012), On the probability of occurrence of extreme space weather events, Space Weather, 10, S02012, doi:10.1029/2011SW000734.
Response: 1. The standard addresses wide area effects. In order to calculate GIC flows, power system engineers were improperly applying across a wide area extreme geolelectric fields derived from single localized observations (for example, 20 V/km across distances of hundreds or even thousands of kilometers). Since geoelectric fields are coherently applied across hundreds of kilometers, the estimation of extreme 100-year geoelectric fields should reflect the geoelectric field magnitude across the same relevant scale. The selection of an area of 500 km provides an adequate scale for spatially coherent fields and is justified by its intended application in power systems, and by the patterns exhibited by IMAGE measurements.		

Organization	Yes or No	Question 4 Comment
2. The extreme value statistics do not assume a Gaussian distribution. POT is based on a Generalized Pareto Distribution It can represent the tails of the statistical distribution appropriately.		
American Electric Power	Yes	AEP remains concerned about the availability of the generic screening models. While the drafting team continues to publicize that the use of these models is an option for meeting the TO/GO requirements in R6, the drafting team has also stated that the development of the models is outside of their scope. In order to address uncertainty regarding these generic thermal models, AEP suggests that NERC commit to making industry-wide generic thermal models available as soon as possible, but no more than 18 months after NERC BOT approval of TPL-007-1. AEP supports the overall direction of this project, and envisions voting in the affirmative if the concerns provided in our response are sufficiently addressed in future revisions of TPL-007-1.
Response: The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Volkmann COnsulting	Yes	The technical justification for spatial average of the 8V/km has not been adequately vetted among peers, the electric utility has not expertise in this average. In addition the SDT has not justified limiting the peak E-field area to only 100km. If it is 500km this is a huge area of the BES to allow a voltage collapse any outage.

Organization	Yes or No	Question 4 Comment
Response: The proposed benchmark has been technically justified and developed by personnel with research and engineering experience. The analysis has been submitted to a technical journal and is in peer review. The E-field extends over a wide area. The local enhancement (beyond the standard geoelectric field amplitude) can be approximately 100-200 km.		
Wisconsin Electric Power Co.	Yes	For requirement 6 transformer assessment, we have a concern that the data required from the manufacturer of the transformer will not be available, especially for older units where the transformer manufacturer is no longer in business. From the 9/10/14 webinar, it is understood that screening models are in development, but there is no guarantee that they will be available to complete the assessment. Since we currently do not have any means at this time to complete this standard requirement, we will have to vote against approval of this standard.
Response: The SDT is addressing this concern with revisions to the Transformer Thermal Assessment white paper which provides a simplified method for conducting transformer thermal assessments. Revisions to the standard and white paper include: (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Ameren	Yes	What is the estimated cost impact to entities for this activity, and what is the estimated marginal improvement in system reliability? We have heard from peers that the data requirements for a large system would take approximately 1 man-year to develop, and the source for this information is from a utility that has performed this activity per the draft standard. We are concerned given this significant investment in time and engineering resources, is there truly a need for a continent-wide standard when only select areas of the continent need to be concerned with GMD evaluation and mitigation?In the GMD Planning Guide document, one reference

Organization	Yes or No	Question 4 Comment
		noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes.We understand from representatives on the IEEE Transformer Committee that there are concerns that the 15 A threshold identified in the GIC standard is too low. We understand that the IEEE will be making a case to raise this threshold because the likelihood of transformer damage is small at that level of DC current (15 A) for the expected transient durations.]
Response: SDT acknowledges cost and time; however, the proposed implementation schedule has taken into account the time needed and was developed with industry input. Revisions have been made to the transformer thermal impact assessment white paper that will enable all entities to perform a transformer thermal assessment and significantly reduce the burden of those assessments. The standard will provide the reliability benefit defined in the project's SAR and FERC directives. The SDT reviewed feedback from manufacturers that are involved with IEEE. With their support the thermal assessment screening criterion has been raised from 15A per phase to 75A per phase. The revised Thermal Impact Assessment white paper provides a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Luminant Generation Company, LLC	Yes	(1) In order to obtain the thermal response of the transformer to a GIC waveshape, a thermal response model is required. To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. A generic thermal response curve (or family of curves) must be provided in the standard or attached documentation that is applicable to the transformers to be evaluated. Without the

Organization	Yes or No	Question 4 Comment
		curve(s), the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to affirmative ballots on this standard. (2) How will entities determine if their transformers will receive a 15Amperes GIC during the test event? (3) It seems like the requirements as written will not incorporate well into a deregulated market with non-integrated utilities. For instance, a TP or PC could instruct a GO to purchase new equipment or shut down their generating unit. This could potentially introduce legal issues in a competitive market. The standard should be revised to eliminate these unintended consequences.
Response: 1. Revisions have been made to the transformer thermal impact assessment white paper that will enable all entities to perform a transformer thermal assessment and significantly reduce the burden of those assessments. 2. The transformer thermal assessment screening criterion has been raised from 15A per phase to 75A per phase. Planning entities determine the peak GIC at each transformers and provide this information to owners in Requirement R5 Part 5.1. 3. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where the Benchmark GMD conditions cannot be met as directed by the FERC order. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction		
Pepco Holdings Inc.	Yes	The White papers are an attempt to explain the details but are not technically accurate. This is not a simple topic and much interpretation of the data is required. The response to GIC is related to the transformer ampere turns which determines the flux produced by the GIC. Increased flux increases the losses thus increasing

Organization	Yes or No	Question 4 Comment
		temperatures. Without looking at the transformer design there is no way to be sure where the increase in flux or heating will create the hottest spot or where the heating will take place. Different transformers designs by different suppliers will react differently. A standard GIC profile curve with short duration peak and longer durations of GIC would allow a better delination of suspectable transformer designs rather than a hard number of 15 amperes per phase. Measurements of GIC and temperatures should be an allowable mitigation technique so the transformer response can be seen under many conditions and if needed the unit can be switched off line.
Response: The white papers are based on current technical information. The asset owner is provided latitude to select an approach that they are comfortable with. The transformer thermal assessment screening criterion has been raised from 15A per phase to 75A per phase which will reduce the number of transformers that require a detailed thermal assessment. The SDT agrees that GIC monitoring is a viable component of a mitigation plan.		
Exelon	Yes	The Exelon affiliates would like to express concern with the reliance on transformer manufacturers to conduct the transformer thermal assessment identified in requirement 6. Specifically, our concern is that some transformer manufacturers may not be willing or able to perform the transformer thermal assessments or to provide the required data to conduct transformer thermal assessments in house. We understand that generic transformer models will be made available in the near future and that software tools will also be available to industry, which will utilize these generic transformer models that can be used should the transformer manufacturer be unable or unwilling to perform the thermal assessments. We believe that this approach could produce overly conservative results which may cause the implementation of mitigation measures that would otherwise be unnecessary if the transformer manufacturer data were used so that more accurate results would be achieved. At least one manufacturer has expressed concern that the use of generic

Organization	Yes or No	Question 4 Comment
		models is incorrect because it does not take into account specific design parameters that only the manufacturers have access to. We also understand the implementation plan for TPL-007 will allow time for industry and the transformer manufacturers to work out the methodology and process associated with conducted transformer thermal assessments. Exelon would urge the transformer manufacturers and the NERC GMD Task Force come to a consensus and provide the necessary support and engagement with industry as well as groups supported by industry in developing transformer models and conducting transformer thermal assessments. We would ask that the Standard Drafting Team review the comments submitted by the transformer manufacturers and address them as appropriate.
Response: the SDT is addressing thermal assessment concerns in this revision by (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.		
Hydro-Quebec TransEnergie	Yes	Hydro-QuÃ©bec has the following concerns with the proposed standard: 1. The GMD Benchmark Event is too severe to be considered as normal event and should be used as a Extreme situation - the drafting team chose to maintain the 8v/Km value and considers that the 1/100 year should be equivalent to Category C and not Category D of current TPL standards. Hydro-QuÃ©bec concurs with Manitoba Hydro's objection on this point. TPL-007 should follow a format with normal and extreme events, with different compliance requirements. A smaller scale GMD Benchmark Event should be considered as normal event. This is not a minority position, since both Manitoba and QuÃ©bec's electric systems cover a non-negligible portion of Canada.

Organization	Yes or No	Question 4 Comment
		2. The GMD Benchmark Event is too preliminary to be applied on Hydro-QuÃ©bec's system and enforce compliance :ï‚§ The study used statistical value of B and convert this into E. The conversion uses conservative hypothesis which provide approximation that do not reflect HQ's reality. The study consider, for an area of 200 km, a constant value of E which does not reflect a realistic situation for Hydro-QuÃ©bec with a 1,000 km long system. The GMD Event should better take into consideration that the magnetic field and electric field are not constant (e.g. E=f(t)) nor uniform (e.g. E=f(x,y)) when studied on a large distance. It depends on time and location.ï‚§ The direct readings of E should be taken into consideration before retaining the GMD Benchmark Event. Some real measured E values exist and should be used to identify the GMC Event.ï‚§ The 5 to 8 V/Km is too high for the Hydro-QuÃ©bec System. The highest global value observed is less than 3 V/Km. The frequency of the maximum local peak value have been observed for less than two minutes over a 167 month period. That could imply enormous investments on the system to comply to this theoretical GMD Event. 3. Even though the drafting team refers to different guides, it appears that the GMD Vulnerability Assessment is not clear enough. Concurring also with Manitoba comment no 4, the drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The harmonic analysis is missing in the standard. 4. At the 1989 event and after, Hydro-Quebec has not experienced any transformer damage due to GIC and have put strong efforts to test and study GIC effect on Transformer. The 15 A criterion is too simplistic and does not take into account the real operating condition and type of transformer. The evaluation proposed in R6 causes a burden that is not relevant for utilities with high power transformers. 5. TPL-007-1 should be consistent with the philosophy applied in Standard PRC-006. In the latter standard, the TP must conduct an assessment when an islanding frequency deviation event occurs that did or should have initiated the UFLS operation. Similarly, if GMD actually causes an event on the system, then the TP or

Organization	Yes or No	Question 4 Comment
		PC should simulate the event to ensure model adequacy (as per R2) and Assessment Review (as per R4) . 6. From a compliance perspective, there is no mention of what the Responsible entity as determined in R1 is supposed to do with the info provided by the TOs and GOs in R6.4. If the thermal impact assessments are supposed to be integrated in the GMD Vulnerability Assessment, it should be specified in R4. 7. The time sequence and delays are unclear regarding requirements R4, R5 and R6. Many interpretations are possible; the following is one example: a- GMD Vulnerability Assessment 1 (R4) b- GIC flow info (R5) c- Thermal impact assessment and report 24 months later d- Integration in GMD Vulnerability Assessment 2.Since assessments are performed about every 5 years, GMD Vulnerability Assessment 2 will only occur 3 years after reception of the thermal impact assessment?The DT should clarify the time sequence and delays between requirements R4, R5 and R6.

Response:

1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events..

2. The standard allows for non-uniform field based on different ground conductivity and geomagnetic latitude. Analysis of IMAGE data set suggest that geolectric field can be coherent for 500 km. There are too few direct E-field readings to extrapolate a 100-year event. 167 months sample does not represent a return period of 100-year.

3. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For harmonic analysis, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.

Organization	Yes or No	Question 4 Comment
4. The 100-year benchmark is more severe than the 1989 storm. Not having failures in 1989 does not mean that no failures are possible with the benchmark. The 15 A criterion is meant to be simplistic, since it is designed as a screening threshold. The thermal assessment screening criterion has been raised from 15A to 75A. 5. The entity responsible for performing a GMD VA must consider the information provided in Requirement R6. A GMD VA is defined as: *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.* The following has been added to the rationale box for R6: *Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.* 6. The SDT agrees that a post-event analysis is a good practice. Such a requirement is not in the scope of the SAR for this project. 7. Timelines in the implementation plan and within the requirements support completion of a GMD VA every 60 months. The rationale boxes for Requirement R5 and R6 to clarify requirements for repeating assessments. *Rationale addition for R5: At a minimum, GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented susceptibility of localized equipment damage due to GMD.* *Rationale addition for R6: The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.*		
ISO New England	Yes	Section 4.2 in the Applicability section of the standard should be revised to state as follows: "Transformers with a high side, wye-grounded winding with terminal voltage greater than 200 kV." As the SDT explained in its answer to comments received on this section during the previous comment period, the standard applies only to transformers, so the words "[f]acilities that" at the beginning of the sentence are unnecessary and can lead to confusion.TPL-007 Requirement R2 should require rotation of the field to determine the worst field orientation. Without this explicit requirement, a Responsible Entity could miss important GMD impacts and, as a result, the standard may not achieve its stated purpose of "establish[ing] requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon." If

Organization	Yes or No	Question 4 Comment
		the Standard Drafting Team does not include this in Requirement R2, then at the least the Standard Drafting Team should include it in the Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System.
Response: TPL-007 does not apply to transformers only. The applicability section 4.2.1 reflects the necessity to include other Elements in the 200 kV network. Field rotation is described in the GMD TF Planning Guide.		
David Kiguel	Yes	R4 provides for completion of Vulnerability Assessments once every 60 calendar months. As written, it could result in assessments performed as far appart as 120 months of each other if one is completed at the beginning of a 60-month period and the subsequent assessment is completed at the end of the following 60-month period. I suggest writing: once every 60 calendar months with no more than 90 months between the completion of two consecutive assessments. Considerable investment expenses could be necessary to comply with the proposed standard. As such, the standard should not proceed without a solid cost/benefit analysis to justify its adoption, especially considering the low frequency of occurrence of events (the frequency of occurrence of the proposed benchmark GMD event is estimated to be approximately 1 in 100 years). Given the low probability, moderate loss of non-consequential load could be acceptable.
Response: The standard specifies the GMD VAs must be conducted every 60 calendar months with no allowance to exceed that time interval. The SDT has been cost conscious in developing the standard; however a specific cost benefit analysis was not in the project scope as defined in the SAR. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require fewer man hours and less cost for transformer thermal assessments due enhancements in the thermal assessment method. The standard permits loss of non-consequential load during a benchmark GMD event.		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Yes	The IESO respectfully submits that the SDT has not provided guidance on achieving an acceptable level of confidence that mitigating actions are needed. To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed from service, we suggest that the SDT add a requirement that says “the TO and GO shall seek the PC’s and TP’s concurrence or approval of thermal analysis technique selection”. The IESO also concurs with Manitoba Hydro and Hydro -Quebec comment that the SDT has not provided guidance on what are acceptable assumptions to make when determining which facilities should be removed as a result of a GMD event. The IESO respectfully reiterates our suggestion to amend the planning process to achieve an acceptable level of confidence as follows:1) Determine vunerable transformers using the benchmark event and simplified assumptions (e.g. uniform magnetic field and uniform earth) and screen using the 15A threshold to determine vulnerable transformers.2) Install GIC neutral current and hot spot temperature monitoring at a sufficient sample of these vunerable transformers.3) Record GIC neutral current and hot-spot temperature during geomagnetic disturbances. 4) Refine modelling and study techniques until simulation results match measurement to within an acceptable tolerance.5) Use the Benchmark event with the refined model to evaluate a need for mitigating actions.

Response: The SDT does not agree with the additional language requiring TO/GO to get PC/TP concurrence on thermal assessment techniques. The SDT believes performing a thermal assessment meets responsibilities for the Transmission Owner and Generation Owner under the NERC functional model. With the limited options for thermal assessment, there is little for the TO or GO to get PC/TP concurrence on in terms of technique selection. The SDT's intent is for the TO and GO to provide results of the thermal impact assessment to the planning entity so that identified issues can be included in the GMD VA and, if necessary, the CAP. Like other planning standards, the planner has latitude for determining how to meet performance criteria.

The SDT believes the proposed standard and application guidelines provide sufficient detail to understand the requirements. Like other planning standards, it is not possible or beneficial for the standard and application guidelines to include all of the technical

Organization	Yes or No	Question 4 Comment
details necessary to cover every implementation of the standard for every entity. The standard specifies the assessment parameters and System performance requirements without being technically prescriptive. The SDT believes technical guidance such as may be found in the GMD Task Force guides and SDT white papers will support performance of the requirements by all applicable entities. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For determining equipment to be removed for the planning event in Table 1 due to harmonics, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.		
Manitoba Hydro	Yes	Manitoba Hydro has five main concerns with the proposed standard: 1. GMD Benchmark Event is too severe - We have made comments previously that we disagree with making a 1/100 year event equivalent to a "Category C" event (as defined in the current TPL standards) in terms of performance requirements. Comments have been made by the drafting team that this is a minority position. Manitoba Hydro's objections are:a) A 1/100 year event "Category D" event is not mandated in Order 779. The FERC Order 779 states "... of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System."b) Manitoba Hydro does not want this to be precedent setting for opening up a review of the extreme events in the current TPL standards and raising the bar for these disturbances in the future. The Transmission Owner should be in the best position to judge their level of risk exposure to extreme events in terms of benefits vs. costs. 2. Thermal Assessments not necessary - We have made recommendations to remove the transformer thermal assessments from TPL-007; specifically remove requirements, R5 and R6. The reason is based on: a) these requirements being burdonesome on utilities in northern latitudes,

Organization	Yes or No	Question 4 Comment
		b) these requirements are based on science that is still evolving,The drafting team is still in the process of finalizing the thermal impact assessment whitepaper. This supporting document should be finalized prior to recommending mandatory standards. c) these requirements having limited reliability benefits,Currently, requirement R6.3 only requires the development of suggested actions. There is no requirement to implement the suggested actions. If no actions are mandated then why is the analysis required? Rather than using a 15 A per phase metric, perhaps R4.4 and R4.5 from TPL-001-4 could be used for guidance where the Planning Coordinator identifies the transformers that are lost or damaged are expected to produce more severe System impacts (eg Cascading) as well as an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence. Such an approach would limit the number of transformers requiring assessment to a manageable number. d) these requirements are not mandated in Order 779.Order 779 does not clearly mention that transformer thermal assessments are required. However, one of the FERC Order 779 requirements implies that a thermal assessment should be done: “If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event.” Damage to critical or vulnerable BPS equipment implies damage due to thermal stress. FERC 779 requires testing for instability, uncontrolled separation or cascading as a result of damage to a transformer or transformers. The TPL-007 standard as drafted does not require an assessment of the impacts of potential loss of a several transformers due to excessive hot spot temperature. Presumably, the hot spot temperature would not coincide to the 8 V/km peak of the benchmark GMD event. The drafting team should specify at what

Organization	Yes or No	Question 4 Comment
		level of GMD (eg 1 V/km) it might be expected that transformers would trip due to hot spot temperature. 3. The TPL-007 standard does not address all of FERC Order 779 - as drafted TPL-007 does not include an assessment of the impacts of equipment lost due to damage that result in instability, uncontrolled separation or cascading failures on the BPS. FERC Order 779 states, “If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event.” Instead it appears that the TPL-007 approach may (R6.3 is not worded clearly as to whether or not mitigation is required) require that all elements impacted by thermal heating get mitigated independ of whether or not their loss results in instability, uncontrolled separation or cascading failures on the BPS. Requiring mitigation on elements for which their loss does not result in instability, uncontrolled separation or cascading failures may result in unnecessary costs with no reliability benefits 4. Harmonic Analysis is missing -The drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The approach proposed in the current standard probably wouldn’t have prevented the 1989 Hydro Quebec event. The 1989 event was a lesser event (compared to the 1-in-100 year benchmark event) in which system MVAR losses as a result of GIC were relatively insignificant and transformer thermal heat impacts were negligible. The 1989 black out occurred due to protection mis-operations tripping of SVCs due to harmonics, which then triggered the voltage collapse. Unfortunately harmonic analysis tools, other than full electromagnetic transient simulation of the entire network, have not been developed to date. A suggestion is to at minimum require an assessment to identify a list of equipment which when lost due to GIC would result in instability, uncontrolled separation or cascading failures on the BPS. For example this would require the tripping of all reactive power devices (shunt capacitors) connected to a common bus. Equipment

Organization	Yes or No	Question 4 Comment
		(such as SVCs and shunt capacitors) that have been checked to ensure protection neutral unbalance protection is unlikely to misoperate or that are immune to tripping due to harmonic distortion would be exempt (equipment may still trip due to phase current overload during periods of extreme harmonics. However, this is expected to be a local single bus or local area phenomena as opposed to region wide issue like in the Quebec 1989 event). 5. GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC's of 24.5 Amps and 20.2 Amps. Analysis of the EPRI SUNBURST GIC data also indicates that the ALL peak GIC values between 10 Amps to 24 Amps were measured in NERC's supposed geoelectric field cut-off zone (between 40 to 60 degrees geomagnetic latitude).

Response: 1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events..

2. Requirements for thermal assessment are within the project scope per the SAR. Revisions have been made to the thermal impact assessment white paper that will enable all entities to perform a thermal assessment and significantly reduce the burden of those assessments. The thermal assessment screening criterion has been raised from 15A per phase to 75A per phase.

3. The proposed standard addresses this FERC directive. The planning entity is responsible for assessing System performance per Table 1 in developing the GMD VA. The planner is provided the thermal assessment results from the equipment owner in R6. Thermal assessment cannot be done exclusively on assets with wide area impact due to the wide-area nature of GMD. For example, a certain group of individual assets may not, individually, have a wide area impact. However, some combination of these assets may

Organization	Yes or No	Question 4 Comment
have a wide area impact. The SDT believes it is necessary for the planner to consider risk for all applicable BES power transformers to ensure that multiple thermal issues do not cause the system to fail to meet performance criteria. 4. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For harmonic analysis, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed and industry practices such as the one recommended be reviewed. 5. GIC measurements are not a reliable/valid indicator of the average geomagnetic field drop off with latitude. The peak GIC measured in any given transformer depends on the orientation of the geoelectric field and the configuration/orientation of the circuits feeding the transformer. Peak geomagnetic field measurements, on the other hand, are system and orientation independent. Analysis of GIC measurement data, without the configuration of the system, is inadequate and quite possibly misleading. For every meaningful GMD event for which there are Sunburst measurements, there are matching geomagnetic field measurements and these measurements are the basis of the average geomagnetic field drop-off scaling factor.		
SaskPower	Yes	1. GMD Benchmark Event appears to be an extreme event - Making a 1/100 year event equivalent to a "Category C" event in terms of BES performance does not seem supported. 2. Thermal Assessments do not seem to be supported. In general, transformer thermal assessments should be limited to transformers that have a confirmed wide area impact. a) the science is still evolving,b) reliability benefits seem limited,&c) not mandated in Order 779.
Response: 1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events.. 2. Requirements for thermal assessment are within the project scope per the SAR. Revisions have been made to the thermal impact assessment white paper that will enable all entities to perform a thermal assessment and significantly reduce the burden of those assessments. The thermal assessment screening criterion has been raised from 15A per phase to 75A per phase.		

Organization	Yes or No	Question 4 Comment
Northeast Utilities	Yes	It appears that the way Requirement 7.3 of the proposed standard is written presents the potential for competition conflicts under FERC Order 1000. Can the SDT provide feedback to the industry as to what, if any, impact evaluation was done on this requirement as it may impact FERC Order 1000. Compliance with Order 1000
Response: The SDT used a planning approach that is consistent with other planning standards which do not create competition conflicts. As with other TPL standards, the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction.		
South Carolina Electric & Gas	Yes	In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. This document has not yet been distributed and, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes, it would be useful to have the opportunity to review it.
Response: The Transformer Modeling Guide is being developed by the NERC GMD TF in the GMD TF Phase II project plan approved by the Planning Committee. Currently commercial GIC software packages include default Reactive Power loss models.		
Kansas City Power and Light	Yes	We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.Benchmark Geomagnetic Disturbance Event DescriptionGeneral Characteristics - Capitalize 'Reactive Power' in the 2nd line of the 3rd bullet under General Characteristics.General Characteristics - Replace 'Wide Area' in the 1st line of the 6th bullet under General Characteristics. The lower case 'wide-area' was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term 'Wide Area' refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC

Organization	Yes or No	Question 4 Comment
		his wide-area overview. We don't believe the usage here is restricted to an RC's Wide Area view. The lower case'wide-area' is used in the paragraph immediately under Figure I-1 under Statistical Considerations.Reference Geoelectric Field Amplitude - In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the 'GIC system model'. In Requirement R2 of the standard a similar reference is made to the 'GIC System model' as well as 'System models'. In the later 'System' was capitalized. Should it be capitalized in this reference also?Statistical Considerations - In the 6th line of the 2nd paragraph under Statistical Considerations, insert 'the' between 'for' and 'Carrington'.Statistical Considerations - In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase '1 in 100 year' is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as '1-in-100'. Be consistent with the usage of this phrase.Screening Criterion for Transformer Thermal Impact AssessmentJustification - In the 3rd line of the 1st paragraph under the Justification section, the phrase '15 Amperes per phase neutral current' appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as '15 Amperes per phase'. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation.Justification - In the 2nd paragraph under the Justification section, the term 'hot spot' appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn't. Whichever, usage is correct (We

Organization	Yes or No	Question 4 Comment
		believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation.Justification - In the 4th line of the Figure 4 paragraph, ‘10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Response: Edits have been made based on this feedback.		
Tri-State Generation and Transmission Association, Inc.	Yes	On page 11 of the "Transformer Thermal Impact Assessment" White Paper it states "To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required." We are interested to know what is meant by "measured"? Does this have to be done in the lab or can this be done through monitoring of existing transformers?
Response: Measured values could come from the lab or the field. Measured values require installed instrumentation. Of note, the standard provides latitude to use models based on calculated values.		
John Kappenman & Curtis Birnbach		Comments submitted by separate file (appended)
Response: 1. The statistics for the 100-year benchmark GMD event were derived using IMAGE magnetometer data from Northern Europe. Since the near-space electric currents dominate the observed horizontal magnetic field variations on the ground, the same overhead currents will generate similar horizontal ground magnetic field variations at different geographical regions. Consequently, it is appropriate to apply the observed magnetic field observations in Northern Europe to derive geoelectric fields in North America, contemplating the specific geological conditions. 2. The developed spatially averaged statistics required 10-s data from a spatially dense magnetometer array. Such data is not available prior to 1993. The data set, however, includes major storms such as October 2003. The geomagnetic latitude scaling is based on global magnetic data that includes, for example, March 1989 and October 2003 extreme storms.		

Organization	Yes or No	Question 4 Comment
3. The published geomagnetic latitude scaling data set includes March 1989. In addition, analysis of limited data from July 1982 indicates that the boundary location for this storm is consistent with the proposed alpha scaling factor in the NERC benchmark. 4. The commenter's approach for using GIC data to calculate geoelectric fields is valid when an accurate power system model, ground conductivity model, specific power system configuration at the time of measurement, and high data rate magnetometer data is available. Calculations are not accurate without all elements. With limited data it is not feasible to develop a technically-justified benchmark using the commenter's approach.		
Mr. Raj Ahuja, Waukesha Mr. Mohamed Diaby, Efacec Dr. Ramsis Girgis, ABB Mr. Sanjay Patel, Smit Mr. Johannes Raith, Siemens		Comments submitted by separate file (appended)
Response to comment on R5 screening criterion: 1. The SDT agrees that 15 A is overly conservative. The screening criterion has been increased to 75 A per phase based on simulations of benchmark GMD event conditions on transformer thermal models. Details are provided in the screening criterion white paper. The new screening criterion is still conservative to account for any condition and all types of transformers to determine if detailed analysis should be performed. 2. At his point in time there is very limited measurement-base information on 3-limb core-type transformers to support a specific threshold. Response to comment on R6 thermal impact assessment. 1. GIC(t) depends on storm orientation and system configuration at the time of the event. During any one event, GIC(t) will be different in every transformer of the system. While it would be desirable to have one-signature-fits-all waveshape, it is unclear what set of parameters would be appropriate for all transformers in one event, let alone all transformers in all events. As stated in the thermal impact assessment white paper, the SDT selected the March 1989 event among others because the waveshape of B(t) had a frequency content and characteristics that resulted in higher temperatures. Newly added simulation results (see Figure 9-3 of the thermal assessment white paper) emphasize this observation. The conservative nature of the benchmark waveshape is not specific to		

Organization	Yes or No	Question 4 Comment
any one transformer model or thermal transfer function. The standard specifies that the thermal impact assessment shall be based on GIC flow information for the benchmark GMD event (Requirement R6 part 6.2). This requirement meets FERC directives which delineate assessment parameters for determining vulnerability of BPS equipment and the BPS as a whole to the benchmark GMD event (Order No. 779 P. 67). The SDT agrees that a general-purpose simplified test waveshape would be desirable. However more research is required to compare the results of such a test waveshape against measurement-based waveshapes, and to determine what parameters would account for the variety of measured waveshapes known to date.		
EIS Council		Comments submitted by separate file (appended)
Response: 1. The proposed benchmark continues the work of the GMD TF and is responsive to FERC Order No. 779 which directs protection against instability, uncontrolled separation, or cascading failures as a result of a benchmark GMD event. For this application, GIC flows should not be based upon statistics derived from single localized observations as advocated by the commenter. 2. There is no direct evidence about the geoelectric field amplitudes for the 1921 Railroad Storm. Absence of recorded data precludes rigorous comparison. The frequency content of the March 1989 storm has been shown in the white paper to a conservative selection from available data. 3. The analogy to bridge design is not valid for considering wide area effects directed by Order No. 779. 4. The March 1989 event provides one parameter of the benchmark GMD event. The commenter is incorrect in referring to this event as the benchmark. The March 1989 event provides a conservative waveshape for transformer thermal impact assessment. The magnitude of the benchmark (used in power flow analysis and transformer thermal impact assessment) is a 100-year event determined through statistical analysis of magnetometer data. 5. Plots in the submitted comments are difficult to understand without scales and legends.		

END OF REPORT

Response to NERC Request for Comments on TPL-007-1

Comments Submitted by the Foundation for Resilient Societies
October 10, 2014

The Benchmark Geomagnetic Disturbance (GMD) Event whitepaper authored by the NERC Standard Drafting Team proposes a conjecture that geoelectric field "hotspots" take place within areas of 100-200 kilometers across but that these hotspots would not have widespread impact on the interconnected transmission system. Accordingly, the Standard Drafting Team averaged geoelectric field intensities downward to obtain a "spatially averaged geoelectric field amplitude" of 5.77 V/km for a 1-in-100 year solar storm. This spatial averaged amplitude was then used for the basis of the "Benchmark GMD Event."[1]

In this comment, we present data to show the NERC "hotspot" conjecture is inconsistent with real-world observations and the "Benchmark GMD Event" is therefore not scientifically well-founded.[2] Figures 1 and 2 show simultaneous GIC peaks observed at three transformers up to 580 kilometers apart, an exceedingly improbable event if NERC's "hotspot" conjecture were correct.

According to Faraday's Law of induction, geomagnetically induced current (GIC) is driven by changes in magnetic field intensity (dB/dt) in the upper atmosphere. If dB/dt peaks are observed simultaneously many kilometers apart, then it would follow that GIC peaks in transformers would also occur simultaneously many kilometers apart. Figure 3 shows simultaneous dB/dt peaks 1,760 kilometers apart during the May 4, 1988 solar storm.

In summary, the weight of real-world evidence shows the NERC "hotspot" conjecture to be erroneous. Simultaneous GIC impacts on the interconnected transmission system can and do occur over wide areas. The NERC Benchmark GMD Event is scientifically unfounded and should be revised by the Standard Drafting Team.

[1] See Appendix 1 for excerpts from the "Benchmark Geomagnetic Disturbance Event Description" whitepaper relating to NERC's "spatial averaging" conjecture.
[2] Data compilations in Figures 1 and 2 are derived from the AEP presentation given to the NERC GMD Task Force in February 2013. Figure 3 is derived from comments submitted to NERC in the Kappenman-Radasky Whitepaper.

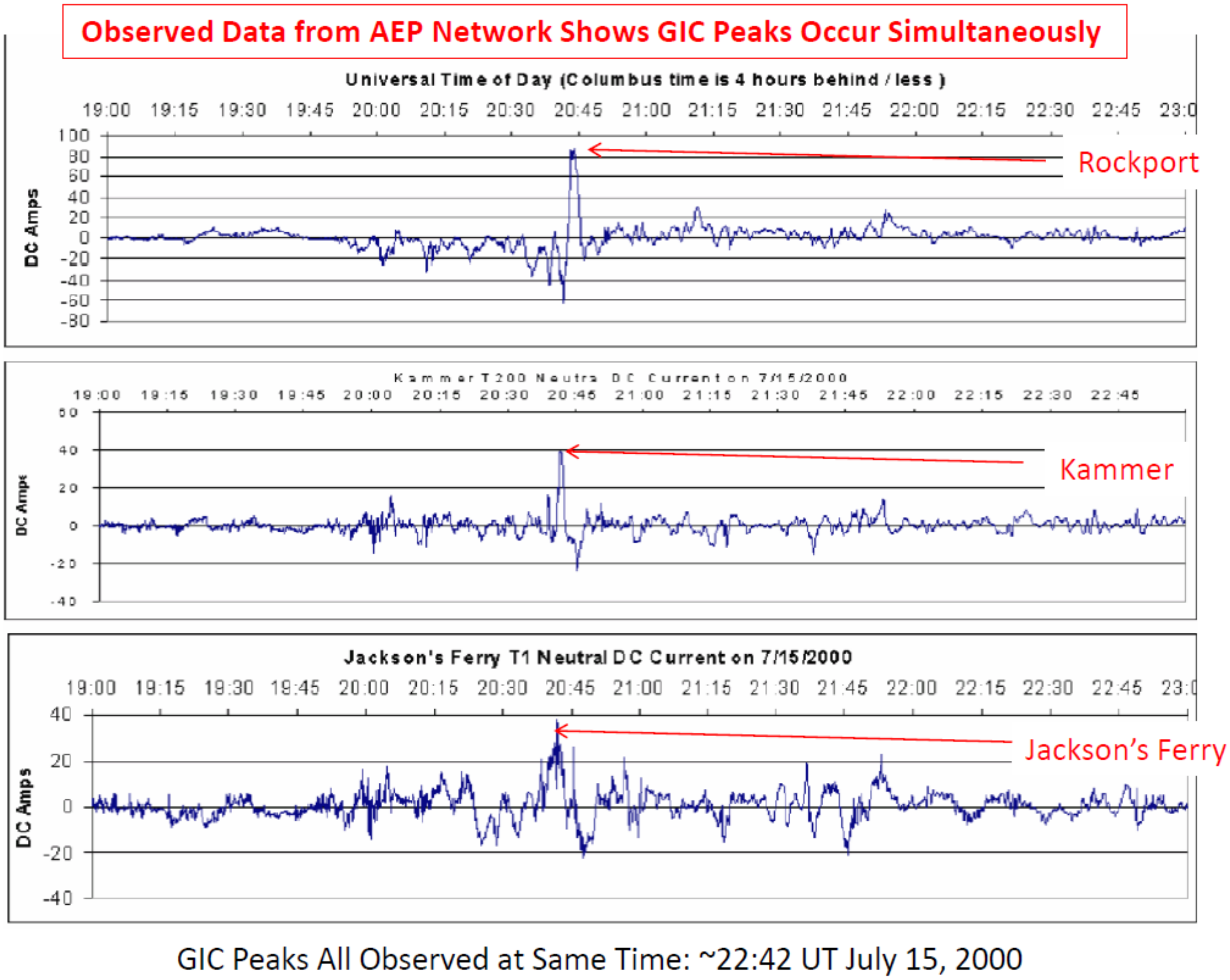

Figure 1. American Electric Power (AEP) Geomagnetically Induced Current Data Presented at February 2013 GMD Task Force Meeting

Locations and Distances for GIC Peaks at Kammer, Jackson's Ferry, and Rockport Transformers

All Peaks Observed Simultaneously at ~22:42 Universal Time on July 15, 2000

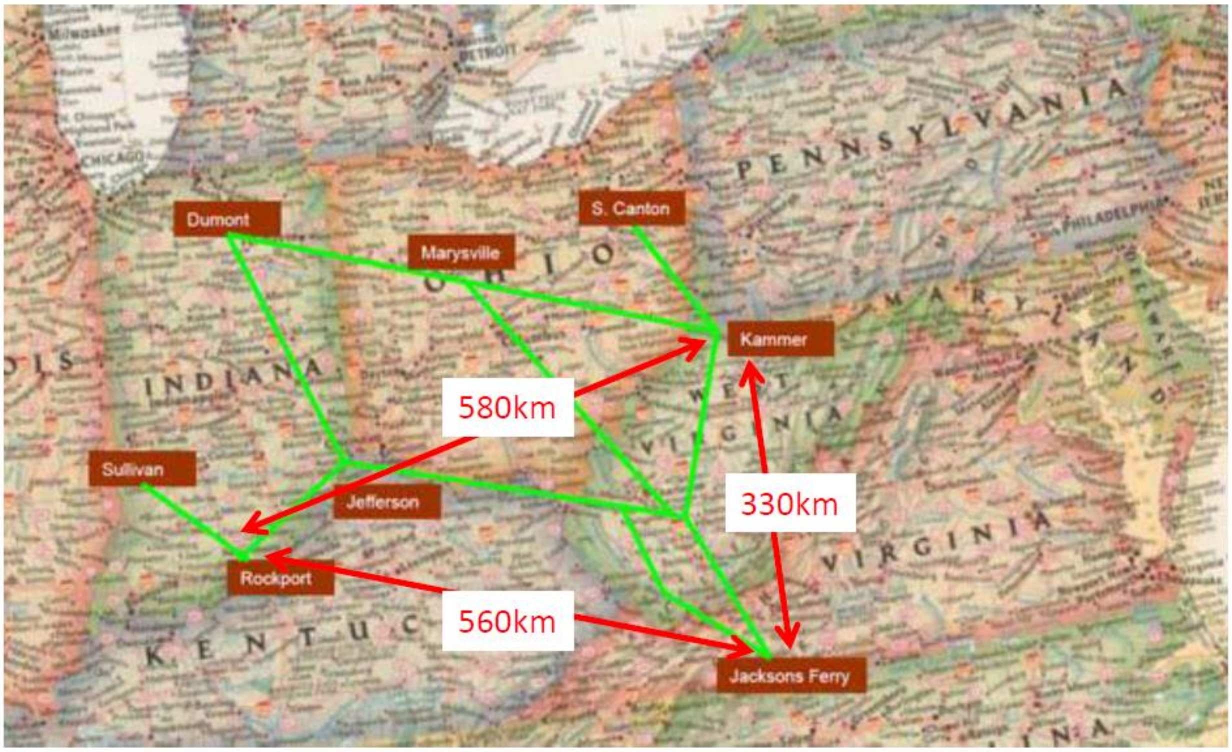

Figure 2. Location of Transformer Substations with GIC Readings on Map of States within AEP Network

Magnetometer Readings from Ottawa and St. John's Observatories During May 4, 1988 Solar Storm Show Simultaneous dB/dt Peaks Far Apart

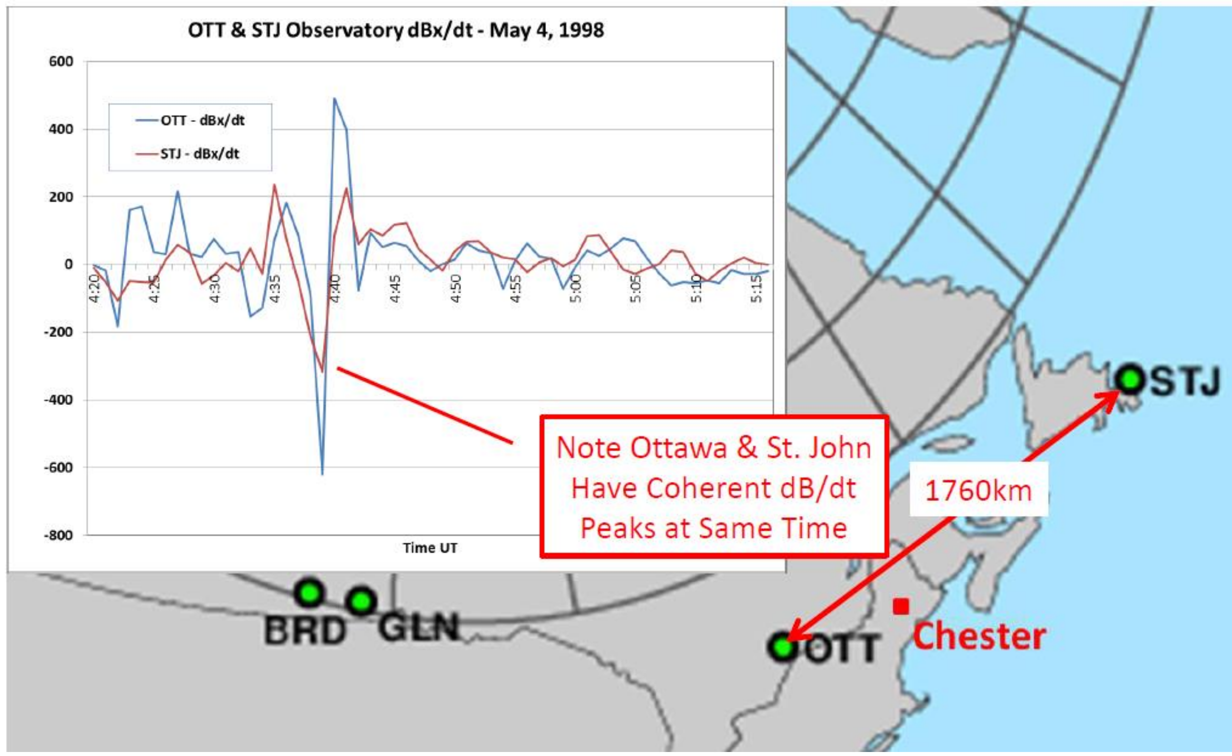

Figure 3. Magnetometer Readings Over Time from Ottawa and St. John Observatories

Appendix 1

Excerpts from
Benchmark Geomagnetic Disturbance Event Description

North American Electric Reliability Corporation

Project 2013-03 GMD Mitigation

Standard Drafting Team

Draft: August 21, 2014

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

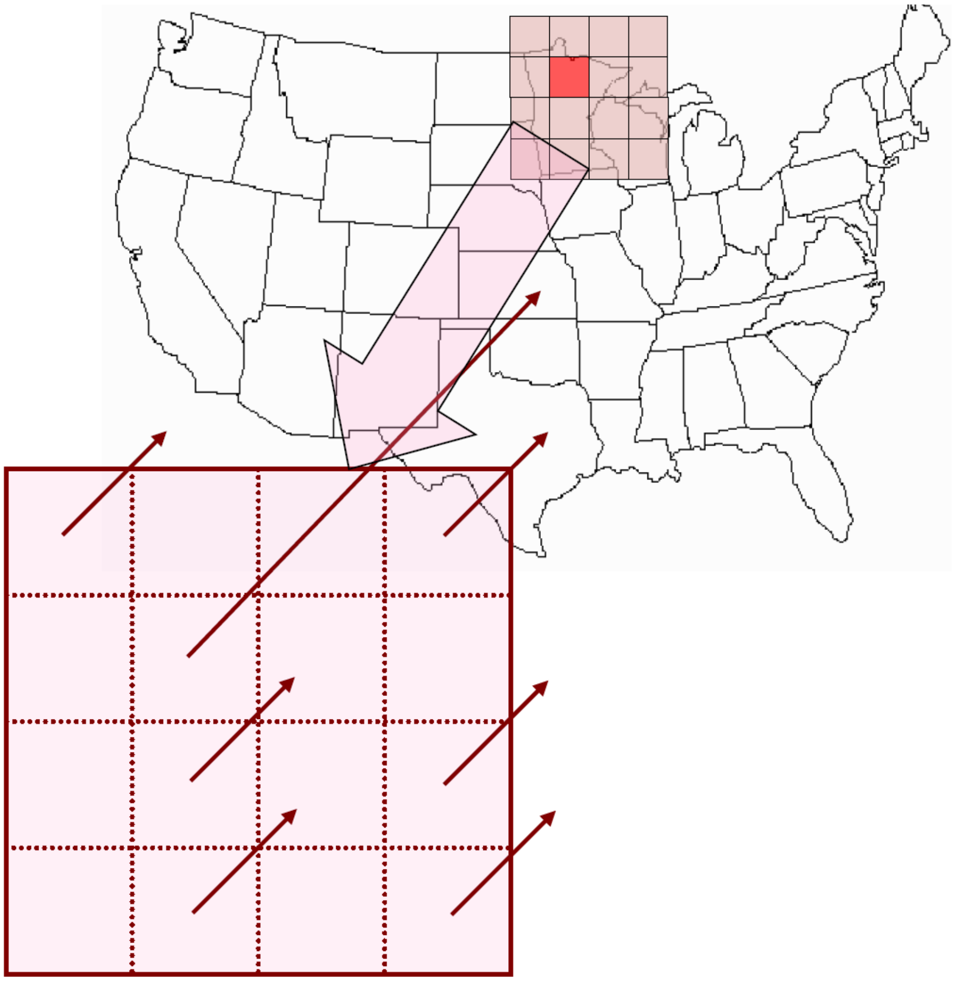

Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

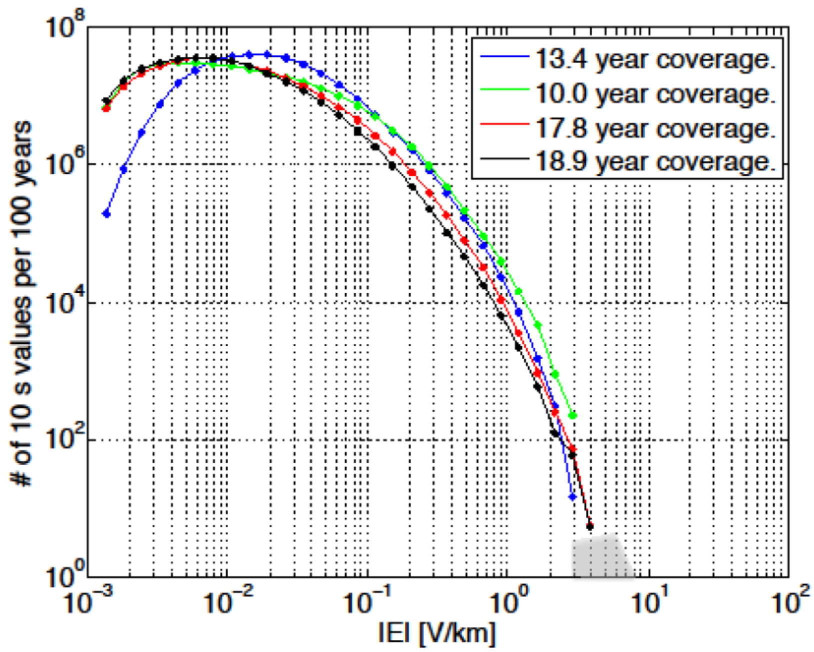

Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

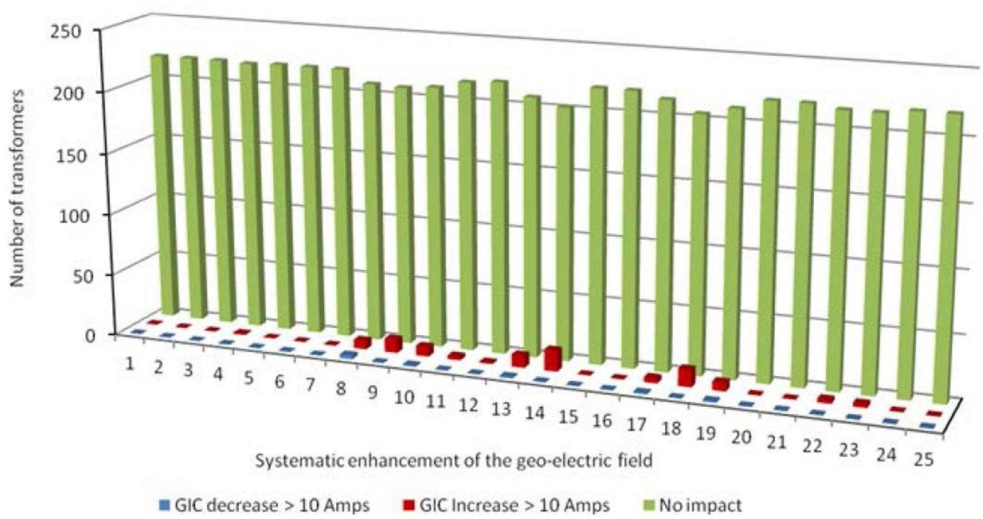

Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1
Submitted to NERC on October 10, 2014

Executive Summary
The NERC Standard Drafting Team has proposed a Benchmark GMD Event based on a 1-in-100 year scenario that does not stand up to scrutiny, as data from just three storms in the last 40 years greatly exceed the peak thresholds proposed in this 100 Year NERC Draft Standard. The Standard Drafting Team then developed a model to estimate Peak Electric Fields (Peak E-Field) at locations within the continental United States for use by electric utilities that also has not been validated and appears to be in error. In these comments technical deficiencies are exposed in both the Benchmark GMD Event and the NERC E-Field model. These deficiencies include:

1. The NERC Benchmark GMD Event was developed using a data set from geomagnetic storm observations in Finland, not the United States.

2. The NERC Benchmark GMD Event was developed using a data set from a time period which excluded the three largest storms in the modern era of digital observations and does not include historically large storms.

3. The NERC Benchmark GMD Event excludes consideration of data recorded during geomagnetic storms in the United States in 1989, 1982, and 1972 that show the NERC benchmark is significantly lower than real-world observations.

4. While it is well-recognized that Peak dB/dt from geomagnetic storms vary according to latitude, observed real-world data from the United States shows that the NERC latitude scaling factors are too low at all latitudes. For storms observed over a 100 year period, NERC latitude scaling factors would be significantly more in error.

5. While it is well-recognized that Peak Electric Fields from geomagnetic storms vary according to regional ground conditions, observed real-world data from the United States shows that the NERC geo-electric field simulation models are producing results that are too low and may have embedded numerical inaccuracies.

6. When the estimated E-Field from the NERC model is compared to E-Field derived from measured data at Tillamook, Oregon during the Oct 30, 2003 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 5.

7. When the estimated E-Field from the NERC model is compared to the E-Field derived from measured data at Chester, Maine during the May 4, 1998 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 2.

8. The errors noted in points 5 and 6 become compounded when combined to determine the NERC Epeak levels for any location. The erroneous NERC latitude scaling factor, and the erroneous NERC geo-electric field model are multiplied together which compounds the errors in each part and produces an enormous escalation in overall error. In the case of Tillamook, it produces results too low by a factor of 30 when compared with measured data.

9. The NERC Benchmark GMD Event, NERC latitude scaling factors, and the NERC geo-electric field model do not use available data from over 100 Geomagnetically-Induced Current monitoring locations within the United States.

In conclusion, the NERC Standard has been defectively drafted because the Standard Drafting Team has chosen to use data from outside the United States and which excludes important storm events to develop its models instead of better and more complete data from within the United States or over more important storm events. GIC data in particular is in the possession of electric utilities and EPRI but not disclosed or utilized by NERC for standard-setting and independent scientific study. The resulting NERC models are systemically biased toward a geomagnetic storm threat that is far lower than has been actually observed and could have the effect of exempting United States electric utilities taking appropriate and prudent mitigation actions against geomagnetic storm threats.

The circumstances presented by this NERC standard development process are extraordinarily unusual, to say the least. Any other credible standards development organization that has ever existed would want to take into consideration all available data and observations and perform a rigorous as possible examination to guide their findings, fully test and validate simulation models etc. Yet this NERC Standards Development Team has decided to not even bother to gather and look at enormously important and abundant GIC data and develop useful interpretations and guidance that this data would provide. NERC has also refused to gather known data on other transformer failures or recent power system incidents that might be associated with geomagnetic storm activity. NERC has developed findings and standards that are entirely based upon untested and un-validated models, models which have also been called into question. These models further put forward results that in various ways actually contradict and ignore the laws of physics. The NERC Standard Development Team behavior parallels to an agency responsible for public safety like the NTSB refusing to look at airplane black box recorder data or to visit and inspect the crash evidence before making their recommendations for public safety. Such behaviors would not merit public trust in their findings.

Discussion of Inadequate Reference Field Storm Peak Intensity and Geomagnetic Field Scaling Factors

As Daniel Baker and John Kappenman had noted in their previously submitted comments in May 2014, there have been a number of observations of geomagnetic storm peaks higher than those in the NERC proposed in TPL-007-1 Reference Field Geomagnetic Disturbance[1]. The purpose of this filing is to further elaborate upon the NERC Draft Standard inadequacies and to also propose a new framework for the GMD Standard.

It is the role of Design Standards above all other factors to protect society from the consequences possible from severe geomagnetic storm events, this includes not only widespread blackout, but also widespread permanent damage to key assets such as transformers and generators which will be needed to provide for rapid post-storm recovery. It is clear that the North American power grid has experienced an unchecked increase in vulnerability to geomagnetic storms over many decades from growth of this infrastructure and inattention to the nature of this threat. In order for the standard to counter these potential threats, the standard must accurately define the extremes of storm intensity and geographic

[1] Daniel Baker & John Kappenman "Comments on NERC Draft GMD Standard TPL-007-1 – Problems with NERC Reference Disturbance and Comparison with More Severe Recent Storm Event", filed with NERC for Draft Standard TPL-007-1, May 2014

footprint of these disturbances. It is only then that the Standard would provide any measure of public assurance of grid security and resilience to these threats.

It is clear from the prior comments provided by a number of commenters that the NERC TPL-007-1 Draft Standard was not adequate to define a 1 in 100 year storm scenario and was not conservative as the NERC Standards Drafting Team claims. Further the NERC Standards Drafting team has not proceeded in their deliberations and developments of new draft standards per ANSI requirements. In developing the Draft 3 Standard now to be voted on and prior drafts, the Standard Drafting Team did not address multiple comments laying out technical deficiencies in the NERC storm scenario. According to the ANSI standard-setting process, comments regarding technical deficiencies in the standard must be specifically addressed.

Figure 1 provides a graphic illustration of the NERC Standard proposed geomagnetic field intensity in nT/min, adapted from Table II-1 of α "Alpha" scaling of the geomagnetic field versus latitude across North America[2].

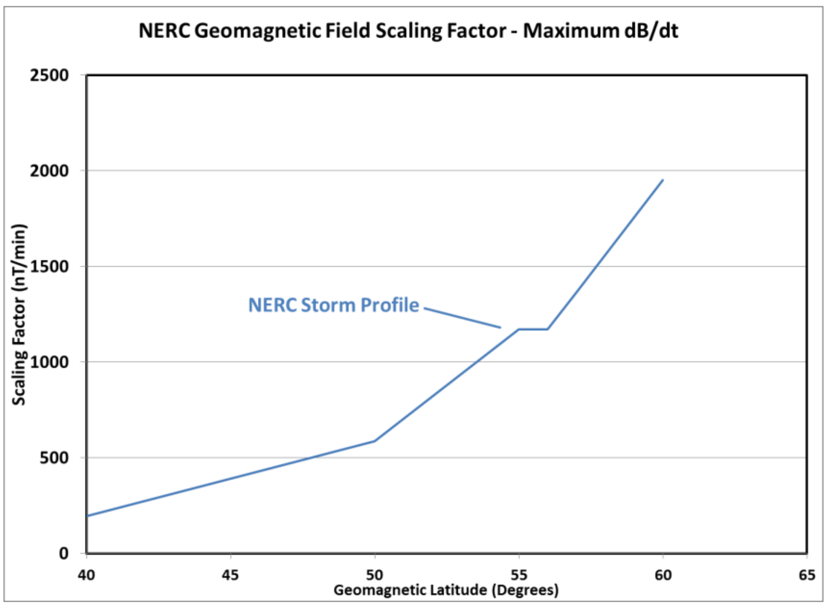

Figure 1 - NERC Proposed Profile of Geomagnetic Disturbance Intensity versus Geomagnetic Latitude

NERC has developed the intensity and profile described in Figure 1 from statistical studies carried out using recent data from the Image Magnetic observatories located in Finland and other Baltic locations[3]. This data base is a very small subset of observations of geomagnetic storm events, it is limited in time and does not include the largest storms of the modern digital data era and is limited in geography as it only focuses on a very small geographic territory at very high latitudes. The lowest latitude observatory in the Image array is at a geomagnetic latitude approximately equivalent to the US-Canada border, so this data set would not be able to explore the profile at geomagnetic latitudes below 55° and therefore reliably characterize the profile across the bulk of the US power grid. The NERC Reference Field excludes the possibility of a Peak disturbance intensity of greater than 1950 nT/min and further excludes that the peak could occur at geomagnetic latitudes lower than 60°. As observation data and other scientific analysis will show, both of these NERC exclusions are in error.

[2] Page 20 of NERC Benchmark Geomagnetic Disturbance Event Description, April 21, 2014.
[3] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

For the NERC Reference profile of Figure 1 to be considered a conservative or 1 in 100 year reference profile, then no recent observational data from storms should ever exceed the profile line boundaries. However as previously noted, the statistical data used by NERC excluded world observations from the large and important March 1989 storm and also from two other important storms that took place in July 1982 and August 1972, a time period that only covers the last ~40 years. In addition, data developed from analysis of older and larger storms such as the May 1921 storm have been excluded by NERC in the development of this reference profile. In just examining the additional three storms of August 4, 1972, July 13-14, 1982, and March 13-14, 1989, a number of observations of intense dB/dt can be cited which exceed the NERC profile thresholds. Figure 2 provides a summary of these observed dB/dt intensities and geomagnetic latitude locations that exceed the NERC reference profile.

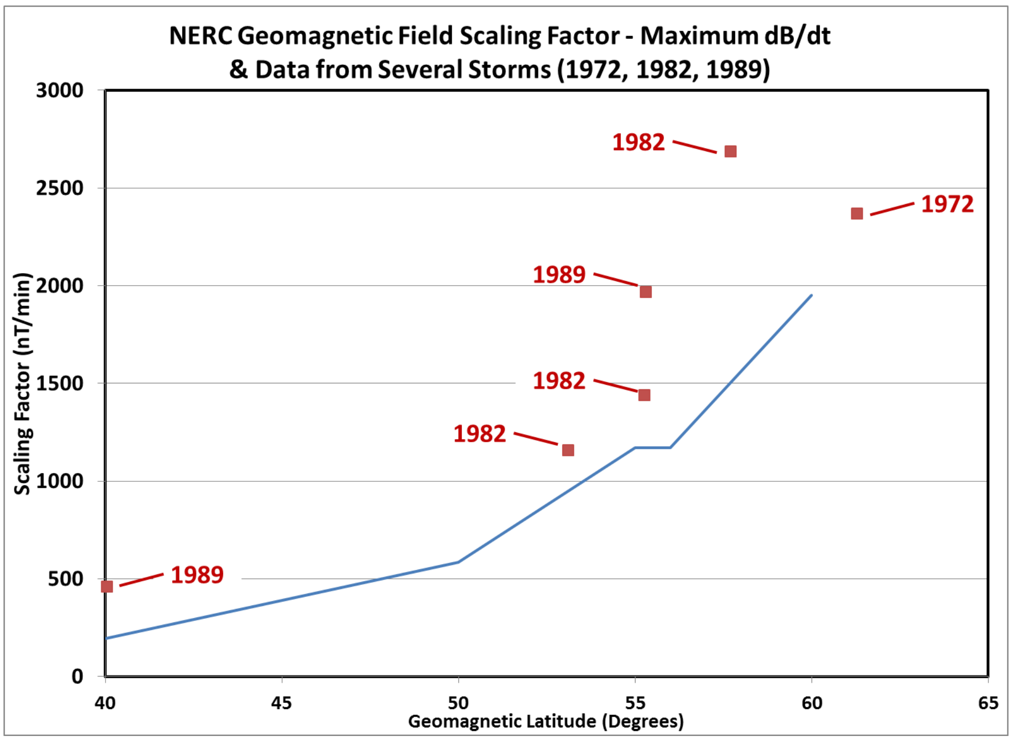

Figure 2 – NERC 100 Year Storm Reference Profile and Observations od dB/dt in 1972, 1982 and 1989 Storms that exceed the NERC Reference Profile

As Figure 2 illustrates that are a number of observations that greatly exceed the NERC reference profile at all geomagnetic latitudes in just these three storms alone. The geomagnetic storm process in part is driven by ionospheric electrojet current enhancements which expand to lower latitudes for more severe storms. The NERC Reference profile precludes that reality by confining the most extreme portion of the storm environment to a 60^{o} latitude with sharp falloffs further south. This NERC profile will not agree with the reality of the most extreme storm events. The excursions above the NERC profile boundary as displayed in Figure 2 clearly points out these contradictions.

In terms of what this implies for the North American region, a series of figures have been developed to illustrate the NERC reference field levels at various latitudes and actual observations that exceed the NERC reference thresholds. Figure 3 provides a plot showing via a red line the ~55^{o} geomagnetic latitude across North America which extends approximately across the US/Canada border. Along this boundary, the NERC Reference profile sets the Peak disturbance threshold at 1170 nT/min, but when considering the three storms not included in the NERC statistics database, it is clear that peaks of ~2700 nT/min have been observed at these high latitudes over just the past ~40 years. As will be discussed later, it is also understood that extremes up to ~5000 nT/min can occur down to these latitudes. Figure 4 provides a similar map showing the boundary at 53^{o} geomagnetic latitude across the US and per the NERC Reference profile, the peak threat level would be limited to 936 nT/min. Yet at this same latitude at the Camp Douglas Station geomagnetic observatory, a peak dB/dt of ~1200 nT/min was observed during the July 1982 storm. Figure 5 provides a map showing the boundary at 40^{o} geomagnetic latitudes and the NERC Reference peak at this location of only 195 nT/min. This figure also notes that in the March 1989 storm the Bay St. Louis observatory observed a peak dB/dt of 460 nT/min, this is 235% larger than the NERC peak threshold.

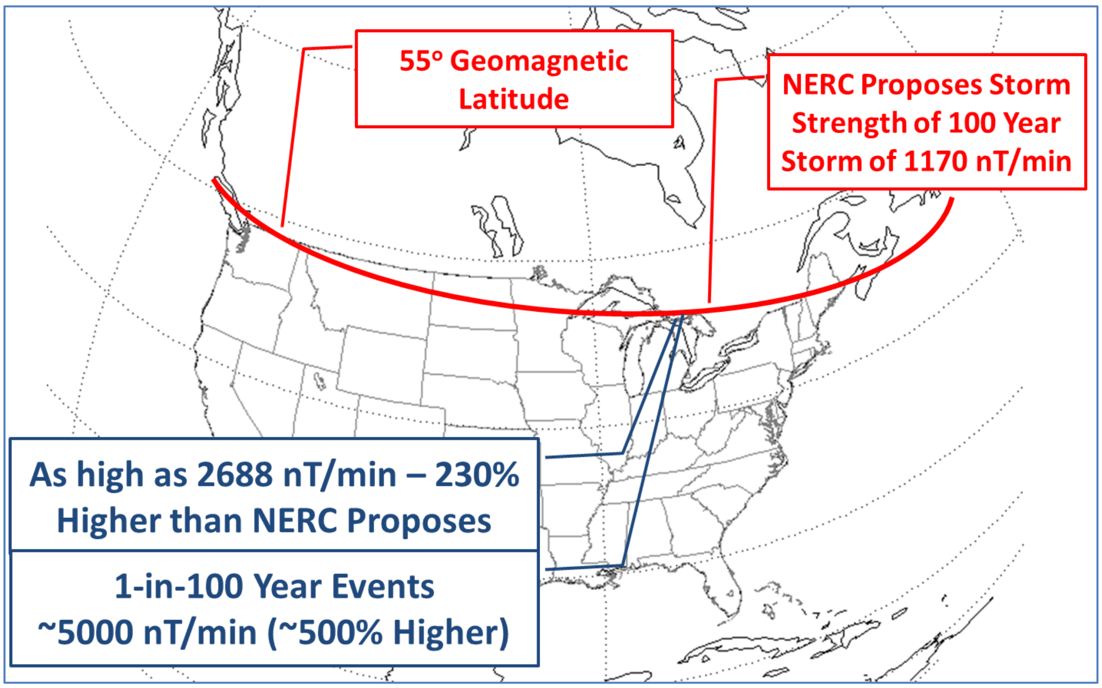

Figure 3 – Comparison of NERC Peak at 55^{o} Latitude versus Actual Observed dB/dt

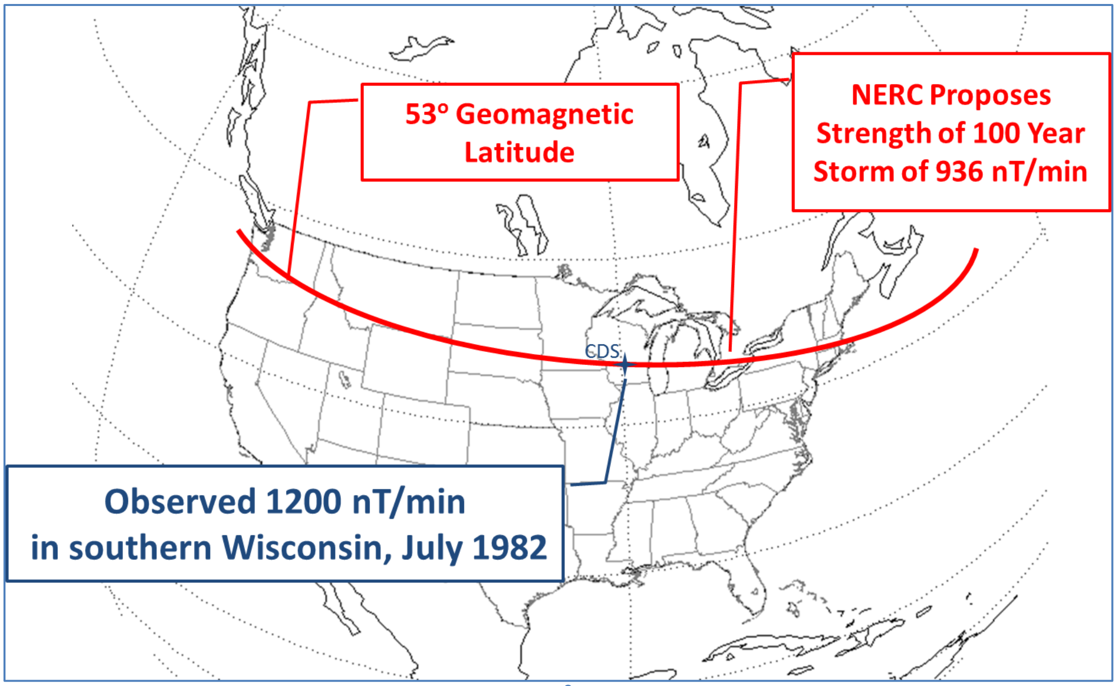

Figure 4 - Comparison of NERC Peak at 53° Latitude versus Actual Observed dB/dt

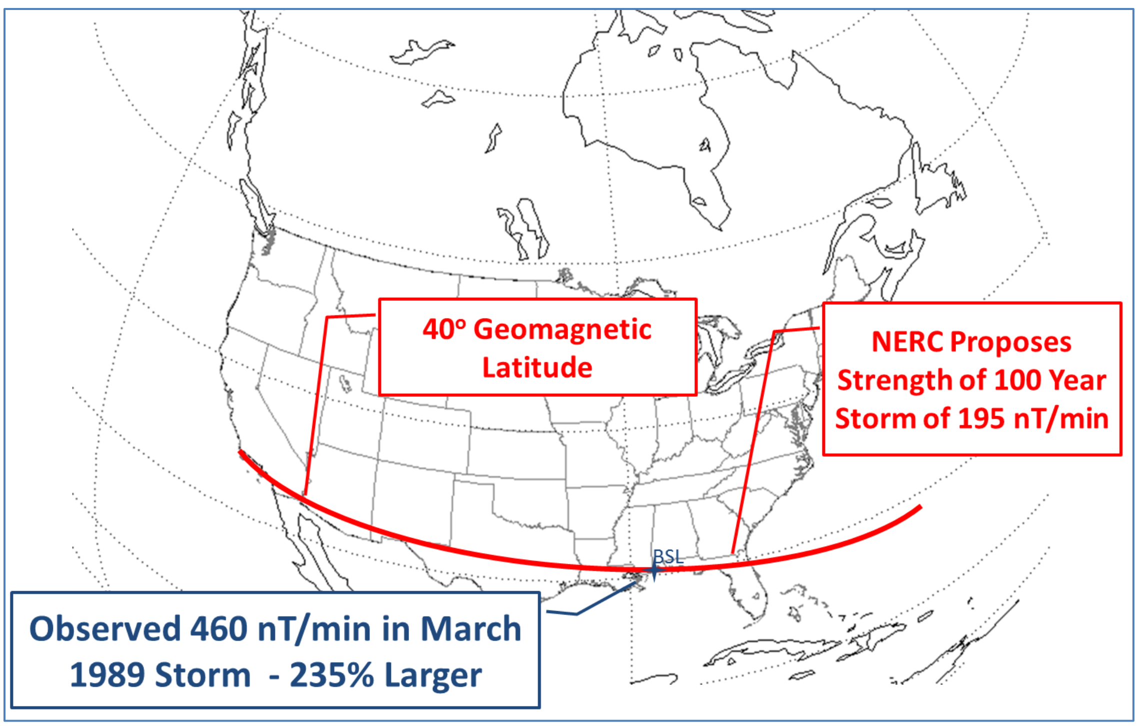

Figure 5 - Comparison of NERC Peak at 40° Latitude versus Actual Observed dB/dt

In summary, these storm observations limited to just three specific storms which happen to fall outside the NERC statistical database all show observations which exceed the NERC Reference profile at all latitudes. This illustrates that the NERC Reference profile cannot be a 1 in 100 year storm reference waveform and is not conservative. It should also be noted that even these three storm events are not representative of the worst case scenarios. In an analysis limited to European geomagnetic observatories, a science team publication concludes “there is a marked maximum in estimated extreme levels between about 53 and 62 degrees north" and that "horizontal field changes may reach 1000-4000 nT/minute, in one magnetic storm once every 100 years"[4]. One advantage of this European analysis, it did not exclude data from older storms like the March 1989 and July 1982 storms, unlike in the case of the NERC database statistical analysis. In another publication the data from the May 1921 storm is assessed with the following findings; "In extreme scenarios available data suggests that disturbance levels as high as ~5000 nT/min may have occurred during the great geomagnetic storm of May 1921"[5]. In another recent publication, the authors conclude the following in regards to the lower latitude expansion of peak disturbance intensity; "It has been established that the latitude threshold boundary is located at about 50–55 of MLAT"[6]. It should be noted that one of the co-authors of this paper is also a member of the NERC Standards drafting team. All of these assessments are in general agreement and all call into question the NERC Reference Profile. Figure 6 provides a comparison plot of these published results with respect to the NERC Draft Standard profile and illustrates the significant degree of inadequacy the NERC Reference profile provides compared to these estimates of 100 Year storm extremes.

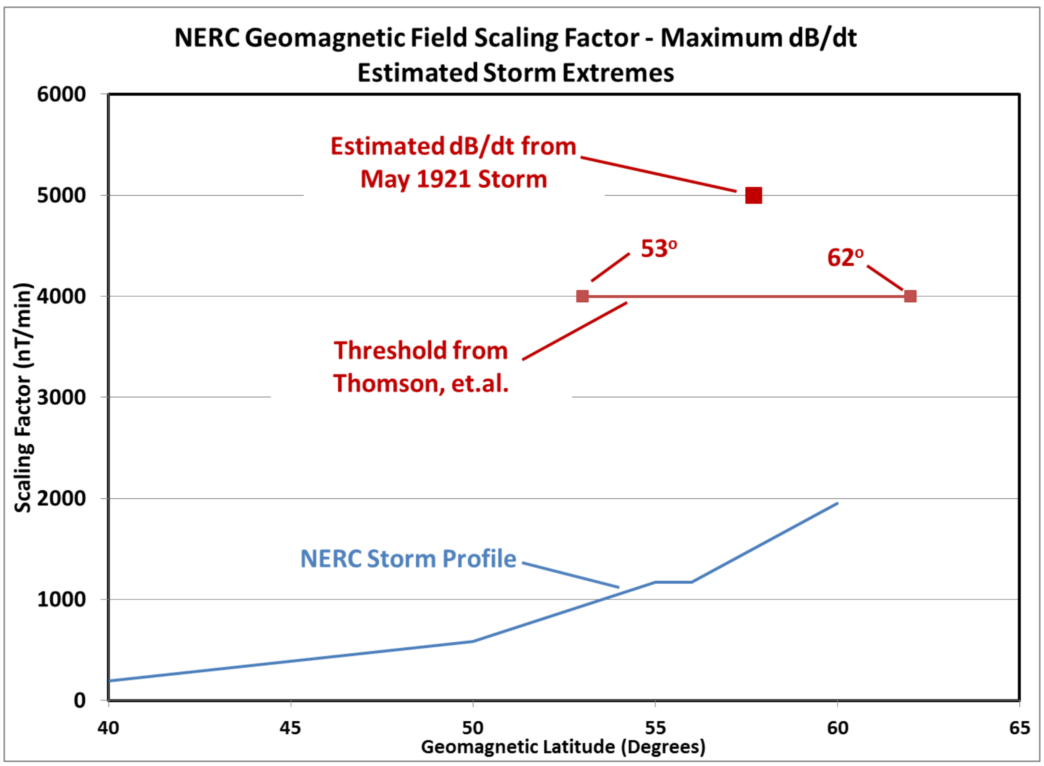

Figure 6 – Scientific Estimates of Extreme Geomagnetic Storm Thresholds compared to Propose3d NERC Draft Standard Profile

[4] Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, Space Weather, 9, S10001, doi:10.1029/2011SW000696, 2011.

[5] John G. Kappenman, Great Geomagnetic Storms and Extreme Impulsive Geomagnetic Field Disturbance Events – An Analysis of Observational Evidence including the Great Storm of May 1921, Advances in Space Research, August 2005 doi:10.1016/j.asr.2005.08.055

[6] Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, Space Weather, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013.

Discussion of Inadequate Geo-Electric Field Peak Intensity

As the prior section of this discussion illustrates, the Peak Intensity of the proposed NERC geomagnetic disturbance reference field greatly understates a 100 year storm event. In prior comments submitted, it was also discovered that the geo-electric field models that NERC has proposed will also understate the peak geo-electric field[7]. In developing the Peak Geo-electric field, NERC has proposed the following formula:

$$E_{peak} = 8 \times \alpha \times \beta \ (\mathrm{V/km})$$

Figure 7 – NERC Peak Geo-Electric Field Formula

As discussed in the last section of these comments the α (Alpha) factor in the above formula is understated at all latitudes for the NERC 100 year storm thresholds. In addition, the White Paper illustrates that the NERC proposed β (Beta) factor will also understate the geo-electric field by as much as a factor of 5 times the actual geo-electric field. When these two factors are included and multiplied together in the same formula, this acts to compound the individual understatements of the α and β factors into a significantly larger understatement of Peak Geo-electric field.

This compounding of errors in the α and β factors can be best illustrated from a case study provided in the Kappenman/Radasky White Paper. In this paper, Figure 27 (page 26) provides the geo-electric field recorded at Tillamook Oregon during the Oct 30, 2003 storm. Also shown is the NERC Model calculation for the same storm at this location. As this comparison illustrates, the NERC model understates the actual geo-electric field by a factor of ~5 and that the actual peak geo-electric field during this storm is nearly 1.2 V/km. Further this geo-electric field is being driven by dB/dt intensity at Victoria (about 250km north from Tillamook) that is 150 nT/min. Tillamook is also at ~50 geomagnetic latitude, so it is possible that the 100 year storm intensity could reach 5000 nT/min or certainly much higher than 150 nT/min. When using the NERC formula to calculate the peak Geo-electric field at Tillamook, the following factors would be utilized as specified in the NERC draft standard: For Tillamook Location, the α Alpha Factor = 0.3 based on Tillamook being at ~50 degrees MagLat, the β Beta Factor = 0.62 for PB1 Ground Model at Tillamook. Then using the NERC formula the derived Epeak would be:

"Tillamook Epeak" = 8 x 0.3 x 0.62 = 1.488 V/km (from NERC Epeak Formula)

In comparison to the ~1.2 V/km observed during the Oct 2003 storm, this NERC-derived Peak is nearly at the same intensity as caused by a ~150 nT/min disturbance. The scientifically sound method of deriving the Peak intensity is to utilize Faraday's Law of Induction to estimate the peak at higher dB/dt intensities. Faraday's Law of Induction is Linear (assuming the same spectral content for the disturbance field), which requires that as dB/dt increases, the resulting Geo-Electric Field also increases linearly. Therefore using the assumption of a uniform spectral content, which may be understating the threat environment, extrapolating to a 5000 nT/min peak environment would project a Peak Geo-Electric Field of ~40 V/km, a Factor of ~30 times higher than derived from the NERC Epeak Formula[8].

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[7] John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.

[8] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/150) = 33.3, Peak Electric = 1.2 V/km *33.3 = 40 V/km

A similar derivation can be performed for the GIC and geo-electric field observations at Chester Maine in the White Paper. From Figure 14 (page 17) the dB/dt in the Chester region reached a peak of ~600 nT/min and resulted in a ~2V/km peak geo-electric field during the May 4, 1998 storm. For this case study, the proposed NERC standard and the formula for the Peak Geo-Electric Field using the following factors for the Chester location, the Alpha Factor = 0.6 based on Chester being at ~55^{o} MagLat, the Beta Factor = 0.81 for NE1 Ground Model at Chester. The NERC Formula would derive the Peak being only ~3.88 V/km.

"Chester Epeak" = 8 x 0.6 x 0.81 = 3.88 V/km (from NERC Epeak Formula)

In contrast to the NERC Epeak value, a physics-based calculation can be made for the case study of the May 4, 1998 storm at Chester. Again, Faraday's Law of Induction can be utilized to extrapolate from the observed 600 nT/min levels to a 5000 nT/min threshold. This results in a Peak Geo-Electric Field of ~16.6 V/km, a Factor of ~4.3 higher than derived from the NERC Formula[9].

Discussion of Data-Based GMD Standard to Replace NERC Draft Standard

As prior sections of this discussion has revealed, the proposed NERC Draft Standard does not accurately describe the threat environment consistent with a 1-in-100 Year Storm threshold, rather the NERC Draft Standard proposes storm thresholds that are only a 1-in-10 to 1-in-30 Year frequency of occurrence. Further, the methods proposed by NERC to estimate geo-electric field levels across the US are not validated and where independent assessment has been performed the NERC Geo-Electric Field levels are 2 to 5 times smaller than observed based on direct GIC measurements of the power grid.

Basic input assumptions on ground conductivity used in the NERC ground modeling approach have never been verified or validated. Ground models are enormously difficult to characterize, in that for the frequencies of geomagnetic field disturbances, it is necessary to estimate these profiles to depths of 400kM or deeper. Direct measurements at these depths are not possible to carry out and the conductivity of various rock strata can vary by as much as 200,000%, creating enormous input modeling uncertainties for these ground profiles. Further it has been shown that the NERC geo-electric field modeling calculations themselves appear to have inherent frequency cutoff's that produce underestimates of geo-electric fields as the disturbance increases in intensity and therefore importance. Hence the NERC Standard is built entirely upon flawed assumptions and has no validations.

A framework for a better Standard which is highly validated and accurate has been provided via the Kappenman/Radasky White Paper and the discussion provided in these comments. As noted in the White Paper, the availability of GIC data and corresponding geomagnetic field disturbance data allowed highly refined estimates to be performed for geo-electric fields and to extrapolate the Geo-Electric Field to the 100 Year storm thresholds for these regions. The primary inputs (other than GIC and corresponding geomagnetic field observations) are simply just details on the power grid circuit parameters and circuit topology. These parameters are also known to very high precision (for example transmission line resistance is known to 4 significant digits after the decimal point). Asset locations are

[9] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/600) = 8.3, Peak Electric = 2 V/km *8.3 = 16.6 V/km

also known with high precision and many commercially available simulation tools can readily compute the GIC for a uniform 1 V/km geo-electric field. This calculation provides an intrinsic GIC flow benchmark that can be used to convert any observed GIC to an regionally valid Geo-Electric Field that produced that GIC. Further this calculation is derived over meso-scale distances on the actual power grid assets of concern. As summarized in a recent IEEE Panel discussion, this approach allows for wide area estimates of ground response than possible from conventional magneto-telluric measurements[10]. Figure 8 provides a map showing the locations of the Chester, Seabrook and Tillamook GIC observations and the approximate boundaries based upon circuit parameters of the ground region that were validated.

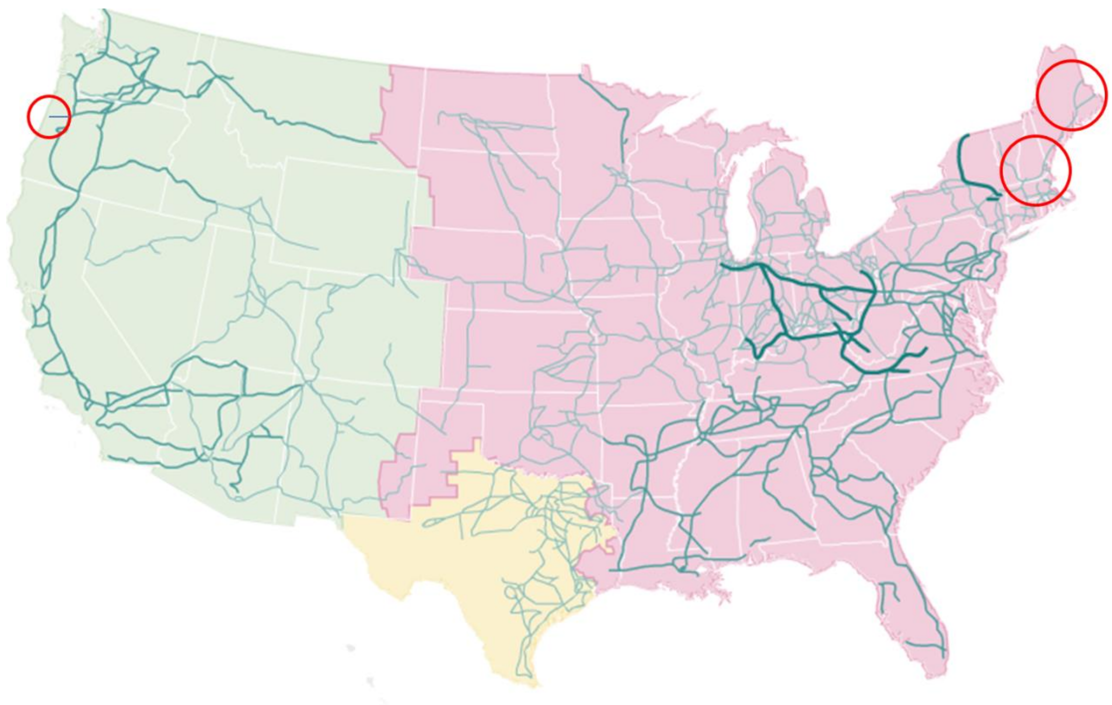

Figure 8 – Red Circles provide Region of Ground Model Validation using GIC observations from Kappenman/Radasky White Paper.

As filed in a recent FERC Docket filing[11], ~100 GIC monitoring sites have operated and are collecting data across the US. Using these analysis techniques and the full complement of GIC monitoring locations, it is possible to accurately benchmark major portions of the US as shown in the map in Figure 9. As shown in this figure, the bulk of the Eastern grid is covered and in many locations with overlapping benchmark regions, such that multiple independent observations can be used to confirm the accuracy of the regional validations. The same is also true for much of the Pacific NW. As noted in Meta-R-319 and shown below is Figure 10 from that report, these two regions are the most at-risk regions of the US Grid.

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[10] Kappenman, J.G., "An Overview of Geomagnetic Storm Impacts and the Role of Monitoring and Situational Awareness", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[11] Foundation for Resilient Societies, "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND", Docket No. RM14-1-000, submitted to FERC on August 18, 2014.

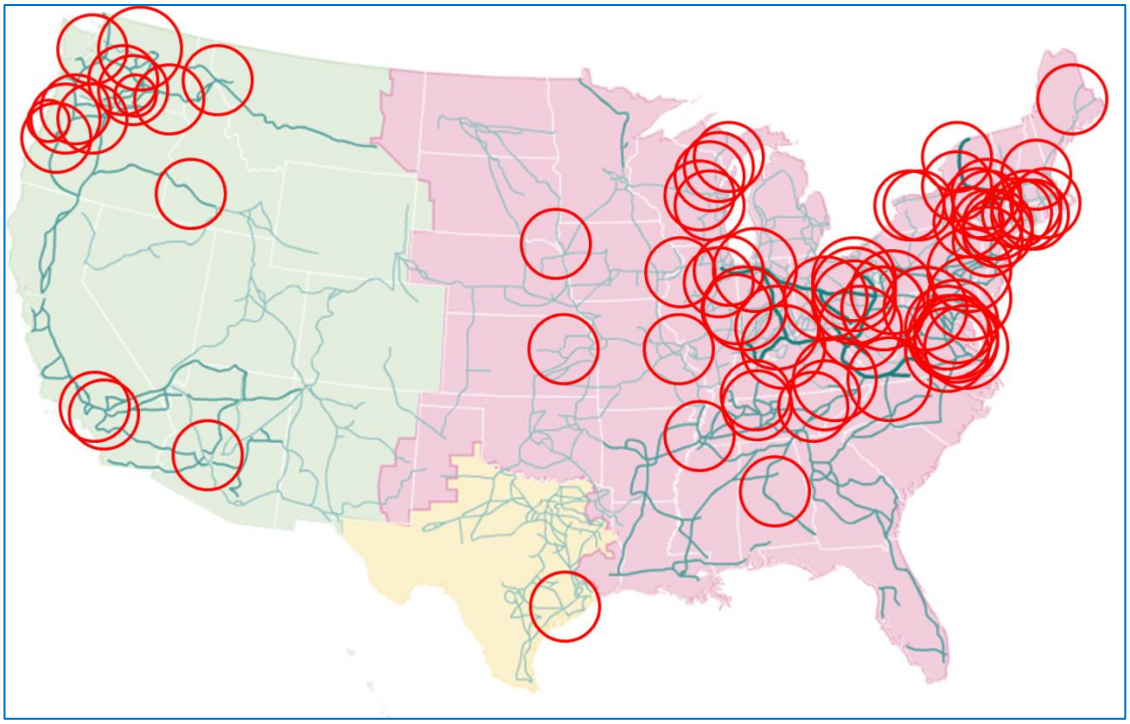

Figure 9 – GIC Observatories and US Grid-wide validation regions.

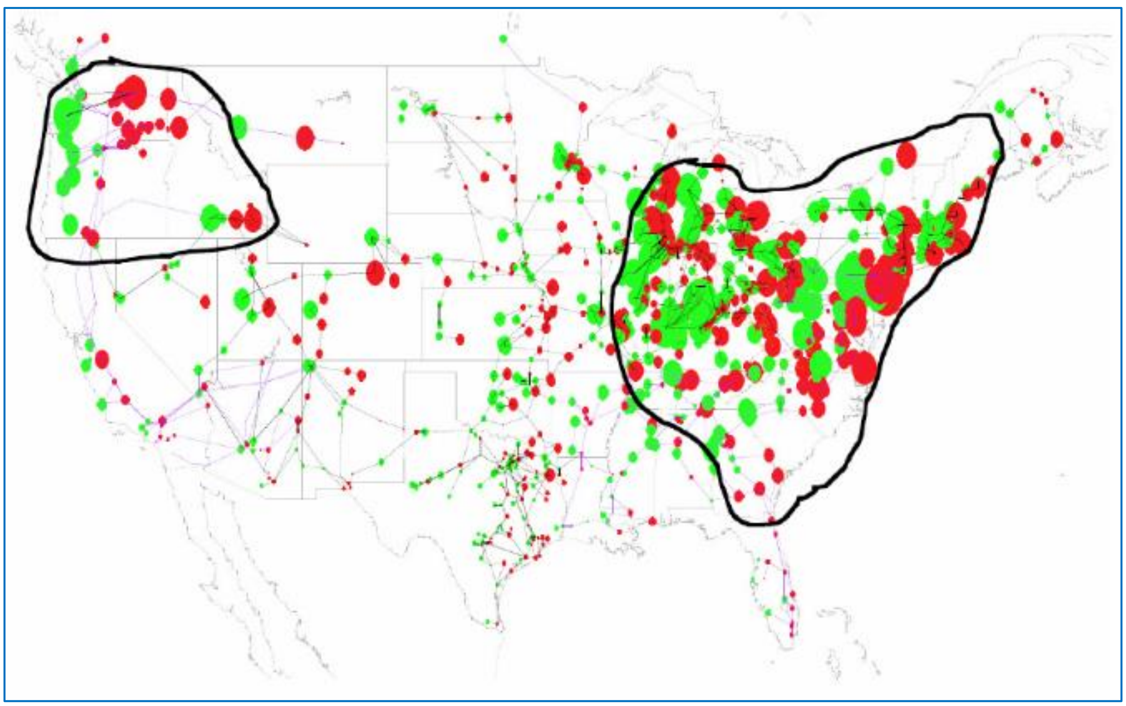

Figure 10 – Map of At-Risk Regions from Meta-R-319 Report for 50° Severe Storm Scenario

Each of these GIC measurements can define and validate the geo-electric field parameters over considerable distance. In the example of the Chester Maine case study, the validations in the case of the 345kV system can extend ~ 250kM radius. At higher kV ratings, the footprint of GIC and associated geo-electric field measurements integrates over an even larger area. As these measurements are accumulated over the US, the characterizations provide a very complete coverage with many overlapping coverage confirmations. These confirmations will also have Ohm's law degree of accuracy, whereas magnetotelluric observations can still have greater than factor of 2 uncertainty[12]. For those areas where perhaps a GIC observation is not available, this region can utilize a base intensity level that agrees with neighboring systems until measurements can be made available to fully validate the regional characteristics.

This Observational-Based Standard further establishes a more accurate framework for developing the standard using facts-based GIC observation data as well as the laws of physics[13], and removes the dependence on simulation models which could be in error. The power system and GIC flows observed on this system will always obey the laws of physics while models may exhibit erratic behaviors and are dependent on the skill/qualifications of the modeler and the uncertainty of model inputs. Models are always inferior to actual data as they cannot incorporate all of the factors involved and can have biases which can inadvertently introduce errors. This Observational Framework methodology is also open and transparent so any and all interested parties can review and audit findings. The validations can be performed quickly and inexpensively across all of these observational regions. It also allows for simple updates once new transmission changes are made over time as well.

Respectfully Submitted by,

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Curtis Birnbach, President and CTO
Advanced Fusion Systems

[12] Boteler, D., "The Influence of Earth Conductivity Structure on the Electric Fields that drive GIC in Power Systems", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[13] For example, Ohm's Law and Faraday's Law of Induction

EIS Council Comments on Benchmark GMD Event

TPL-007-1

Submitted on October 10, 2014

Introduction

The Electric Infrastructure Security Council's mission is to work in partnership with government and corporate stakeholders to host national and international education, planning and communication initiatives to help improve infrastructure protection against electromagnetic threats (e-threats) and other hazards. E-threats include naturally occurring geomagnetic disturbances (GMD), high-altitude electromagnetic pulses (HEMP) from nuclear weapons, and non-nuclear EMP from intentional electromagnetic interference (IEMI) devices.

In working to achieve these goals, EIS Council is open to all approaches, but feels that industry-driven standards, as represented by the NERC process, are generally preferable to government regulation. That said, government regulation has proven necessary in instances (of all kinds) when a given private sector industry does not self-regulate to levels of safety or security acceptable to the public. EIS Council is concerned that the new proposed GMD benchmark event represents an estimate that is too optimistic, and would invite further regulatory scrutiny of the electric power industry.

The proposed benchmark GMD event represents a departure from previous GMDTF discussions, where the development of the "100-year" benchmark GMD event appeared to be coming to a consensus, based upon statistical projections of recorded smaller GMD events to 100-year storm levels. These levels of 10 – 50 V/km, with the average found to be 20 V/km, were also in agreement with what were thought to be the storm intensity levels of the 1921 Railroad Storm, which, along with the 1859 Carrington Event, were typically thought to be the scale of events for which the NERC GMDTF was formed to consider.

The new approach described in April 14, 2014 Draft (and subsequent GMDTF meetings and discussions) contains several key features that EIS Council does not consider to yet have enough scientific rigor to be supported, and would therefore recommend that a more conservative or "pessimistic" approach should be used to ensure proper engineering safety margins for electric grid resilience under GMD conditions. These are:

1. The introduction of a new "spatial averaging" technique, which has the effect of lowing the benchmark field strengths of concern from 20 V/km to 8 V/km;

2. A lack of validation of this new model, demonstrating that it is in line with prior observed geoelectric field values;

3. The use of the 1989 Quebec GMD event as the benchmark reference storm, rather than a larger known storm such as the 1921 Railroad storm;

4. The use of 60 degrees geomagnetic latitude as the storm center; and

5. The use of geomagnetic latitude scaling factors to calculate expected storm intensities south of 60 degrees.

Spatial Averaging and Model Validation

The introduction of the spatial averaging technique is a novel introduction to discussions of the GMDTF. While the concept could prove to have validity, the abrupt change to a new methodology at this time is not fully understood by the GMDTF membership, nor has it yet had any peer review by the larger space weather scientific community. In order to ensure confidence that this is a proper approach, it is necessary that this approach be validated with available data via the standard peer-review process.

Prior findings of the GMDTF of a 20 V/km peak field values were shown to be in line with prior benchmark storms such as the 1921 Railroad storm, for which there is very good magnetometer data across the United States and Canada. Even for the 1989 Quebec Storm, on which this new benchmark is supposed to be based, it is not clear whether the new spatial averaging technique has been demonstrated to be in line with the known magnetometer data. This would seem to be a fairly straightforward validation of this new model, but is currently lacking in the description of the new approach.

The spatial averaging method also appears to be at odds with standard engineering safety margin design approaches. As an example, if the maximum load for a bridge is 20 tons, but the average load is 8 tons, a bridge is designed to hold at least 20 tons, or more typically 40 tons, a factor of two safety margin over the reasonably expected maximum load. It is recommended that the screening criteria be increased to encompass the maximum credible storm event, rather than an average, in line with typically accepted best practices for engineering design.

The description of the method does describe that within the expected spatially-averaged GMD event of 8 V/km, that smaller, moving "hot spots" of 20 V/km are expected. It therefore seems prudent for electric power companies to analyze the expected resilience of their system against a 20 V/km geoelectric field, as any given company could find themselves within such a "hot spot" during a GMD event.

One further point to consider is that, while the GMDTF scope does not at present include EMP, the unclassified IEC standard for the geoelectric fields associated with EMP E3 is 40 V/km. Should the scope of the GMDTF or FERC order 779 ever be expanded to include EMP E3, 40 V/km is the accepted international standard, something to consider when setting the benchmark event, as any given power company could find themselves subject to the maximum credible EMP E3 field.

1989 Quebec Storm as the Benchmark Event

The 1989 Quebec Storm is very well-studied event, and is a dramatic example of the impacts of GMD on power grids. The loss of power in the Province of Quebec, failure of the Salem transformer, and other grid anomalies associated with the storm are all well documented. The GMDTF was formed, and FERC Order 779 issued, to ensure grid resilience for events that will be much larger than the 1989 Quebec Storm, such as the 1921 Railroad Storm. The two figures below show a side-by-side comparison of the 1989 and 1921 storms. The geographic size, and also the latitude locations are quite striking.

The use of the 1989 Quebec Storm as the benchmark event is of concern because simply scaling the field strengths of the 1989 Storm higher (an "intensification factor" of 2.5 is used), but leaving the same geographic footprint, does not appear to be a valid approach. While the 2.5 scaling factor is described to produce local "hot spots" of 20 V/km, in agreement with earlier findings, it fails to consider the well-known GMD phenomena that the electrojets of larger storms shift southward, as can be seen in comparing the two figures. By using the geographic footprint of the 1989 storm, the new benchmark will predict geoelectric field levels that are incorrect for geomagnetic latitudes below 60 degrees, where the center of the new benchmark storm has been set.

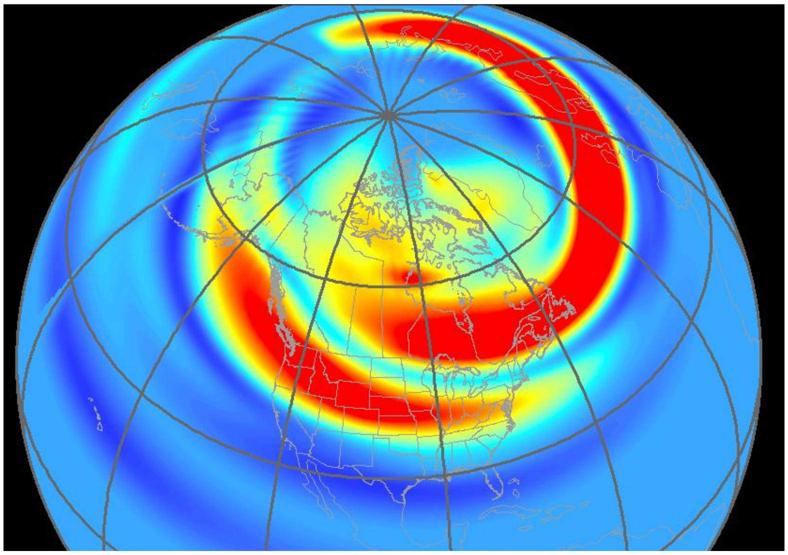

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

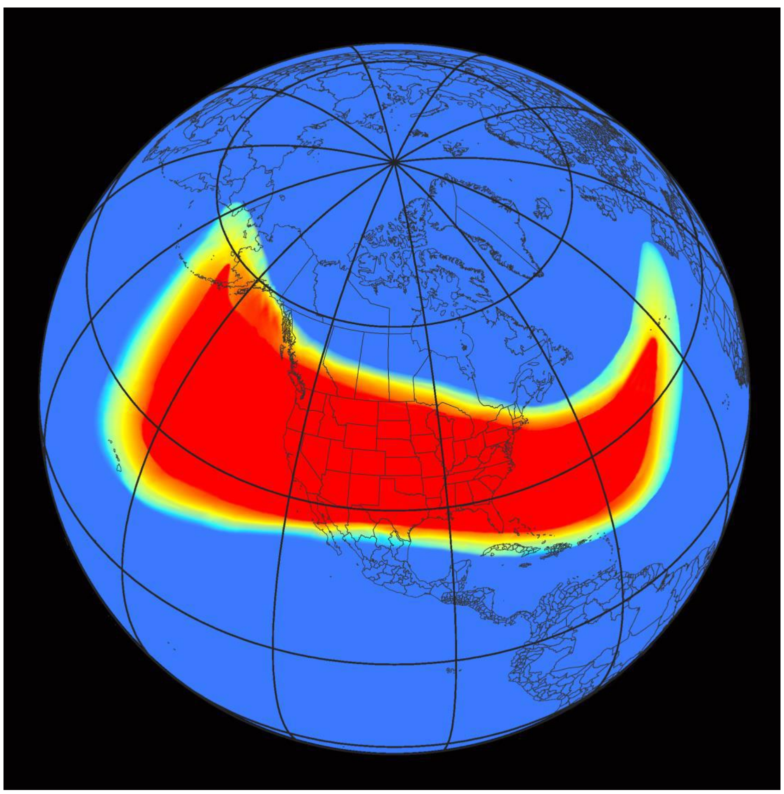

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

As the figures above show, GMD events larger than the 1989 Quebec event are expected to be larger in overall geographic laydown (continental to global in scale), and also to be centered at lower geomagnetic latitudes than the 1989 storm, due to a southward shifting of the auroral electrojet for more energetic storms. While the latitudinal scaling factor α may be correct for a storm like the 1989 Storm and centered on 60 degrees geomagnetic latitude, use of these scaling factors does not appear to be valid for GMD events where the storm will be centered at a lower latitude, and have a larger geographic footprint. While the β factor - which captures differences in geologic ground conductivity - will remain valid under all storm scenarios, the α factors would only be valid for a storm centered at 60 degrees. For example, in looking at figure 2 above, the storm is quite large, and centered at (roughly) 40 – 45 degrees North Latitude. The correct α factor for 45 degrees in this case would be 1, rather than the 0.2 value that would be correct for a storm centered at 60 degrees North Latitude. As it is not known what the center latitude of any given storm center would be, it would seem that the use of the 60 degree storm center latitude and subsequent α scaling factors is not fully supported.

Supporting scientific evidence for the use of the 60-degree storm center and scaling factors is cited in TPL-007-1. The supporting paper by Ngwira et al[1], however, discusses a "latitude threshold boundary [that] is associated with the movements of the auroral oval and the corresponding auroral electrojet current system." The latitude boundary found in the paper, however, is given as 50 degrees magnetic latitude, rather than 60 degrees. The study determines this boundary based on observations of ~30 years of geomagnetic storm data. While the data set is large, it does not contain very large storms, on the scale of the 1921 Railroad storm. As the largest storms are known to have the largest southward electrojets shifts, it would seem prudent that the benchmark be adjusted to be consistent with the supporting scientific finding of 50 degrees magnetic latitude, and a subsequent re-calculation of the α scaling factors for latitudes below 50 degrees.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed

[1] Ngwira, Pulkkinen, Wilder, and Crowley, *Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications*, Space Weather, Vol. 11 121-131 (2013)

discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there would seem to be a scientific inconsistency in using a benchmark storm centered at 60 degrees geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location down to 50 degrees, as cited in the supporting document. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, centered at the cited 50 degree magnetic latitude threshold boundary, with subsequently updated latitude scaling factors for lower latitudes, as the benchmark event against which the individual electric power companies can analyze their system resilience.

Comments on NERC TPL – 007 – 1 (R5)

Reference *screening criterion for GIC Transformer Thermal Impact Assessment*

Issue

A level of 15 Amps / phase was selected for this screening. It was based on temperature rise measurements of structural parts of some core form transformers reaching a level of 50 K upon application of 15 Amps / phase DC.

Comment – 1

Since the time constant of the transformer structural parts is typically in the 10 – minute range, these temperatures were reached after application of the DC current for 10's of minutes (up to 50 minutes in some cases). The high level GIC pulses are typically of much shorter duration and the corresponding temperature rise would be a fraction of these temperature rises.

Recommendation

Upon performing temperature calculations of the cases referenced in the NERC screening White paper for GIC pulses, we suggest the following:

1. The 15 Amps / phase could be kept as a screening criterion for GIC levels extending over; say, 30 minutes.
2. A higher level of 50 Amps / phase is used as a screening criterion for high – peak, short – duration pulses. A 3 – minute duration of 50 Amps would be equivalent to, and even more conservative than, the 15 Amps / phase steady state.

Comment – 2

The 15 Amps / phase level was based on measurements on transformers with core – types, other than 3 – phase, 3 – limb cores. Three Phase core form transformers with 3 – limb cores are less susceptible to core saturation.

Recommendation

We suggest that, for 3 – phase core form transformers with 3 – limb cores, a higher level of GIC, for example 30 or 50 Amps / phase, is selected for the screening level for the base GIC and correspondingly a much higher level, for example, 100 Amps / phase, for the high – peak, short – duration GIC pulses.

Note 1:

The revised screening criterion recommended in the above, is not only more appropriate technically than what is presently suggested in the NERC "Thermal screening" document, but also will reduce the number of transformers to be thermally assessed probably by a factor of 10; which would make the thermal evaluation of the $\geq$ 200 kV transformer fleet in North America to be more feasible to be done in the time period required by the NERC document.

Note 2:

It is to be noted that proposing one value of GIC current for screening for all transformer types (core form vs. shell form), sizes, designs, construction, etc. is not technically correct. However, for the sake of moving the NERC document forward, we agreed to follow the same path but provide the improved criterion we recommended above.

Submitted by:

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Mr. Mohamed Diaby, Efacec
Dr. Ramsis Girgis, ABB
Mr. Sanjay Patel, Smit
Mr. Johannes Raith, Siemens

Comments on NERC TPL – 007 – 1 (R6)

"GIC Transformer Thermal Impact Assessment"

Issue

The document should have a Standard GIC signature to be used for the thermal impact Assessment of the power Transformer fleet covered by the NERC document.

Comment – 1

Users would not be able to predict, to any degree of accuracy, what GIC signature a transformer would be subjected to during future GMD storms. This is since the actual GIC signature will depend on the specific parameters and location of the future GMD storms. Unless a user requires thermal assessment of their fleet of transformers to actual GIC signatures, the user should be able to use a Standard GIC Signature; where the parameters of the signature (magnitudes and durations of the different parts of the signature) would be specified by the user.

This is parallel to the standard signatures used by the transformer / utility industry Standards (IEEE & IEC) for lightning surges, switching surges, etc.; where standard signatures (wave – shapes) are used for evaluating the dielectric capability of transformers.

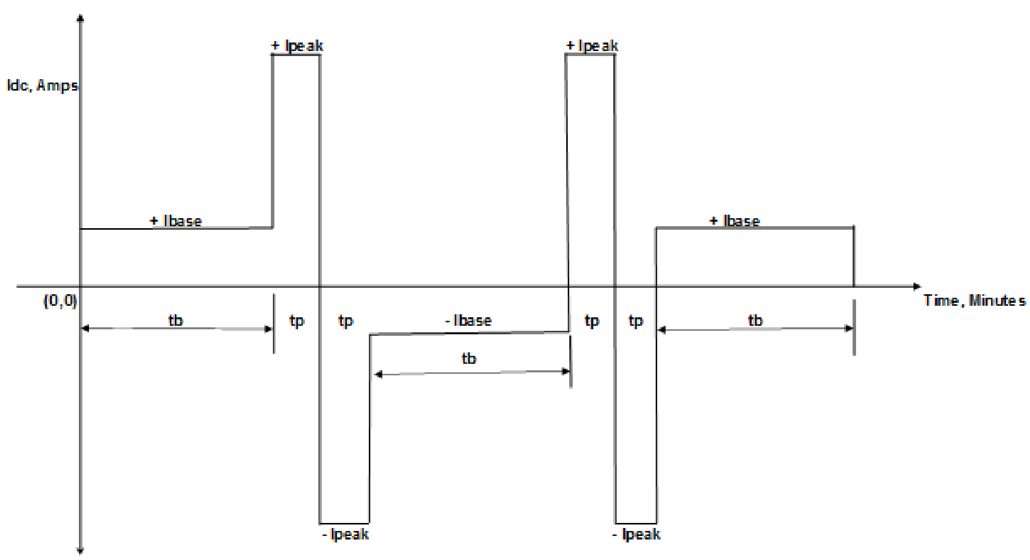
Recommendation

We recommend that the NERC document suggest using the Standard GIC signature, proposed in the upcoming IEEE Std. PC57.163 GIC Guide, shown below. This signature was based on observation / study of a number of signatures of measured GIC currents on a number of power transformers located in different areas of the country. It was recognized that GIC current signatures can be generally characterized by a large number of consecutive narrow pulses of low – to – medium levels over a period of hours interrupted by high peaks of less than a minute, to several minutes, duration. Therefore, GIC signatures are made of two main stages of GIC; namely:

- Base Stage: Consists of multiples of small – to – moderate magnitudes of GIC current sustained for periods that could be as short as a fraction of an hour to several hours.
- Peak GIC Pulse Stage: Consists of high levels of GIC pulses of durations of a fraction of a minute to several minutes.

Utilities would provide values of the Base GIC (I_{base}) current and the Peak GIC current pulses (I_{peak}) specific to their power transformers on their respective power system. These two parameters are to be determined based on the geographic location of the transformer as well as the part of the power grid the transformer belongs to. For standardization purposes, the time durations of the base GIC and GIC pulses; t_b and t_p, respectively, can be fixed at 20 minutes and 3 minutes; respectively. Also, the full duration of the high level GMD event can be standardized to be 2 or 3 hours long; encompassing several cycles of the GIC signature. These parameters can be as conservative as they need to be.

Specifying a Standard GIC signature for the thermal Assessment of the thousands of power Transformers covered by the NERC document would allow using generic / simplified (but sufficiently accurate) thermal models for the thermal Assessment and, hence, a significantly less effort. On the other hand, the thermal Assessment of transformers, to be done correctly, for different more complex GIC signatures, would require much more time to complete.



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