# Consideration of Comments

## Project 2013-03 Geomagnetic Disturbance Mitigation

The Geomagnetic Disturbance Mitigation Drafting Team 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 June 13, 2014 through July 30, 2014. Stakeholders were asked to provide feedback on the standards and supporting material through a special electronic comment form. There were 74 sets of comments, including comments from over 180 individuals from approximately 130 companies representing all 10 Industry Segments as shown in the table on the following pages.

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

**Summary Consideration:**

As a result of comments received, the drafting team revised the standard, implementation plan, and reference material to incorporate a number of stakeholder recommendations that improve the standard. Although Section 4.12 of the NERC Standard Processes Manual indicates that the drafting team is not required to respond in writing to comments from the previous posting when it has identified the need to make significant changes to the standard, the drafting team is providing summary responses to the comments received in order to facilitate stakeholder understanding.

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

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

- Implementation Plan. The SDT changed the overall implementation schedule from 4-years to 5-years to address stakeholder concerns with coordination, model development, and resource limitations. The revised implementation plan provides six-months from the effective date of the standard for Planning Coordinators and Transmission Planners to identify responsibilities (R1) and extends other requirements in a similar manner. Additionally, the initial performance of transformer thermal impact assessments is extended to 48-calendar months from the effective date.
- Voltage Criteria. Requirement R3 (previously R4) was modified to allow responsible entities more flexibility in determining the acceptable voltage performance criteria.
- Requirement R6 (Transformer Thermal Impact Assessment). The SDT added language to clearly indicate that the requirement applies to BES power transformers meeting the applicability section 4.2 of the proposed standard. The timeline for completing thermal assessments was increased from 12-calendar months to 24-calendar months from receipt of required information from the planning entity. Also, the VRF was changed from HIGH to MEDIUM for consistency with NERC and FERC VRF Guidelines.
- Table 1 – Steady State Planning. Guidance that may have restricted manual or automatic Load shedding to meet performance requirements has been removed from footnote 3 (previously footnote 4) as suggested by stakeholders. The SDT agrees with this change as it is better aligned with the project's intent of developing standards to prevent voltage collapse, cascading and uncontrolled islanding during a 100-year benchmark event. Additionally, the SDT removed duplicative notes from Table 1.
- Attachment 1 – Benchmark GMD Event. The drafting team revised guidance for assuming an earth conductivity scaling factor when a model is not known. Attachment 1 now allows planners to select a conservative scaling factor from an adjacent physiographic region rather than use a default value. Also, an earth conductivity scaling factor was added to Table 3 for Florida, based on research by the U.S. Geological Survey (USGS).
- Requirements were reordered in response to stakeholder recommendations for a more logical sequencing. Several clarifications were made to the requirements, measures, and supporting material based on stakeholder feedback.

Several stakeholders commented on the 15 Amperes screening criterion proposed by the SDT for transformer thermal impact assessment. Stakeholders agreed with the criterion and supporting justification provided in the white paper but suggested that a separate, higher threshold should be established specifically for 3-phase power transformers. The SDT carefully considered the recommendation and the information available to support technical justification. The SDT agrees that the threshold for 3-phase 3-limb transformers is expected to be higher than the threshold for single phase units. However there is insufficient thermal measurement data of 3-phase 3-limb transformers to develop a technical justification at this time.

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 | | | | | | | | | |
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| 1. | Group | Sandra Shaffer | PacifiCorp | | | | | | X | | | | |
| N/A | | | | | | | | | | | | | |
| 2. | Group | Phil Hart | Associated Electric Cooperative, Inc. - JRO00088 | X | | X | | X | X | | | | |

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

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
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| 3. | 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 | NPCC | 3 |
| 3. | Greg Campoli | New York Independent System Operator | NPCC | 2 |
| 4. | Ben Wu | Orange and Rockland Utilities Inc. | NPCC | 1 |
| 5. | Chris de Graffenried | Consolidated Edison Co. of New York, Inc. | NPCC | 1 |
| 6. | Gerry Dunbar | Northeast Power Coordinating Council | NPCC | 10 |
| 7. | Peter Yost | Consolidated Edison Co. of New York Inc. | NPCC | 3 |
| 8. | Kathleen Goodman | ISO - New England | NPCC | 2 |
| 9. | Ayesha Sabouba | Hydro One Networks Inc. | NPCC | 1 |
| 10. | Mark Kenny | Northeast Utilities | NPCC | 1 |
| 11. | Christina Koncz | PSEG Power LLC | NPCC | 5 |
| 12. | Helen Lainis | Independent Electricity System Operator | NPCC | 2 |
| 13. | Alan MacNaughton | New Brunswick Power Corporation | NPCC | 9 |
| 14. | Bruce Metruck | New York Power Authority | NPCC | 5 |
| 15. | Silvia Parada Mitchell | NextEra Energy, LLC | NPCC | 5 |
| 16. | Lee Pedowicz | Northeast Power Coordinating Council | NPCC | 10 |
| 17. | Wayne Sipperly | New York Power Authority | NPCC | 5 |
| 18. | Robert Pellegrini | The United Illuminating Company | NPCC | 1 |
| 19. | David Ramkalawan | Ontario Power Generation, Inc. | NPCC | 5 |
| 20. | Brian Robinson | Utility Services | NPCC | 8 |

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 4. | Group | Thomas Popik | Foundation for Resilient Societies | | | | | | | | X | | |

N/A

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

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | Bob Solomon | Hoosier Energy Rural Electric Cooperative, Inc. | RFC | 1 |
| 2. | John Shaver | Southwest Transmission Cooperative, Inc. | WECC | 1, 4, 5 |
| 3. | Shari Heino | Brazos Electric Power Cooperative, Inc. | ERCOT | 1, 5 |
| 4. | Kevin Lyons | Central Iowa Power Cooperative | MRO | 1 |

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 5. | Scott Brame | North Carolina Electric Membership Corporation | SERC | 3, 4, 5 |
| 6. | Mark Ringhausen | Old Dominion Electric Cooperative | RFC | 3, 4 |
| 7. | Ginger Mercier | Prairie Power, Inc. | SERC | 3 |
| 8. | William Hutchison | Southern Illinois Power Cooperative | SERC | 1, 5 |
| 9. | Steve McElhaney | South Mississippi Electric Power Association | SERC | 1, 3, 4, 6 |
| 10. | Ellen Watkins | Sunflower Electric Power Corporation | SPP | 1 |
| 11. | Matt Caves | Western Farmers Electric Cooperative | SPP | 1, 5 |

| Group/Individual | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 6. Group | Peter Heidrich | FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | | | | | | | | | | X |

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | John Giddens | Reedy Creek Improvement District | FRCC | 3, 4, 5, 6 |
| 2. | Matt Pawlowski | Florida Power & Light/Nextera Energy | FRCC | 1, 3, 5, 6 |
| 3. | Glenn Dooley | Duke Energy - Florida | FRCC | 1, 3, 5, 6 |
| 4. | Ron Donahey | Tampa Electric Company | FRCC | 1, 3, 5, 6 |
| 5. | Ken Simmons | Gainesville Regional Utilities | FRCC | 1, 3, 5 |
| 6. | Ted Hobson | JEA | FRCC | 1, 3, 5 |
| 7. | Jim Howard | Lakeland Electric | FRCC | 1, 3, 5, 6 |
| 8. | Keith Mutters | Orlando Utilities Commission | FRCC | 1, 3, 5, 6 |
| 9. | Karen Webb | City of Tallahassee | FRCC | 1, 3, 4, 5, 6 |
| 10. | Mike Antonell | Calpine Corporation | FRCC | 5, 6 |
| 11. | Gary E. Willer | Indiantown Cogeneration, L.P. | FRCC | NA |
| 12. | Doug Jensen | Northern Star Generation/Vandolah | FRCC | 5 |
| 13. | Helen Nalley | Southern Power Company | FRCC | 5 |
| 14. | Carol Chinn | Florida Municipal Power Agency | FRCC | 3, 4, 5, 6 |
| 15. | Steve Wallace | Seminole Electric Cooperative, Inc. | FRCC | 1, 3, 4, 5, 6 |
| 16. | Frank Holmes | Clay Electric Cooperative | FRCC | NA |
| 17. | Dennis Minton | Florida Keys Electric Cooperative | FRCC | 1, 3 |
| 18. | Cairo Vanegas | Fort Pierce Utilities Authority | FRCC | 3, 4 |
| 19. | O.J. Garcia | City of Homestead | FRCC | 3 |
| 20. | Greg Woessner | Kissimmee Utility Authority | FRCC | 1, 3, 5 |
| 21. | Frank Cain | Lee County Electric Cooperative | FRCC | 1, 3 |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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|---|---|---|---|
| 22. Clay Lindstrom | City of Lake Worth | FRCC | 1 |
| 23. Tim Beyrle | Utilities Commission of New Smyrna Beach | FRCC | 4 |
| 24. Randy Hahn | Ocala Utility Services | FRCC | 3 |
| 25. Robert Doty | City of Vero Beach | FRCC | 1 |
| 26. Israel Melendez | Constellation Energy | FRCC | 5 |
| 27. Paterick McGovern | Georgia Transmission Corp. | FRCC | 1 |

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 7. | 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 |
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| 8. | Group | Connie Lowe | Dominion | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Randi Heise | | MRO | NA |
| 2. Mike Garton | | NPCC | 5 |
| 3. Louis Slade | | RFC | 5, 6 |
| 4. Larry Nash | | SERC | 1, 3, 5, 6 |

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

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. William Smith | FirsEnergy Corp | RFC | 1 |
| 2. Cindy Stewart | FIrstEnergy Corp | RFC | 3 |
| 3. Doug Hohlbaugh | Ohio Edison | RFC | 4 |
| 4. Ken Dresner | FirstEnergy Solutions | RFC | 5 |
| 5. Kevin Querry | FirstEnergy Solutions | RFC | 6 |
| 6. Richard Hoag | FirstEnergy Corp | RFC | NA |

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 10. | Group | Joe Wilson | Tacoma Public Utilities | X | | X | X | X | X | | | | |

N/A

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 11. | Group | David Greene | SERC Planning Standards Subcommittee | | | | | | | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Jim Kelley | PowerSouth | | |
| 2. Shih-Min Hsu | Southern Company Services | | |
| 3. Phil Kleckley | SCE&G | | |

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 4. James Manning | NCEMC | | |
| 5. David Greene | SERC | | |

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| 12. Group | Paul Haase | Seattle City Light | X | | X | X | X | X | | | | |

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

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| 13. Group | Tom McElhinney | JEA | X | | X | | X | | | | | |

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

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| 14. Group | Kaleb Brimhall | Colorado Springs Utilities | X | | X | | X | X | | | | |

N/A

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| 15. Group | Erika Doot | Bureau of Reclamation | X | | | | X | | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Richard Jackson | Bureau of Reclamation | WECC | 1 |

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| 16. Group | Michael Lowman | Duke Energy | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Doug Hills | | RFC | 1 |
| 2. Lee Schuster | | FRCC | 3 |
| 3. Dale Goodwine | | SERC | 5 |
| 4. Greg Cecil | | FRCC | 6 |

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| 17. Group | Brandy Spraker | Tennessee Valley Authority | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Marjorie Parsons | | SERC | 3 |
| 2. Ian Grant | | SERC | 6 |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 3. DeWayne Scott SERC 1 | | | | | | | | | | | | | |
| 18. | 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 Company | MRO | 1, 3, 5 |
| 3. | Dan Inman | Minnkota Power Coop | MRO | 1, 3, 5, 6 |
| 4. | Dave Rudolph | Basin Electric Power Coop | 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 | 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 |

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| 19. | Group | Wayne Johnson | Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | X | | X | | X | X | | | | |
| N/A | | | | | | | | | | | | | |
| 20. | 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 |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 4. | | PPL Susquehanna, LLC | RFC | 5 |
| 5. | | PPL Montana, LLC | WECC | 5 |
| 6. | Elizabeth Davis | PPL EnergyPlus, LLC | MRO | 6 |
| 7. | | | NPCC | 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 |
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| 21. | Group | Kathleen Black | DTE Electric | | | X | X | X | | | | | |

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | Kent Kujala | NERC Compliance | RFC | 3 |
| 2. | Daniel Herring | NERC Training & Standards Development | RFC | 4 |
| 3. | Mark Stefaniak | Merchant Operations | RFC | 5 |
| 4. | Dave Szulczewski | DE-EE Relay Eng | | |

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 22. | Group | Shannon V. Mickens | SPP Standards Review Group | | X | | | | | | | | |

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | Shannon V. Mickens | | SPP | 2 |
| 2. | Matt Boredelon | | SPP | 1, 3, 5, 6 |
| 3. | Neal Faltys | | SPP | 1, 3, 5 |
| 4. | Michael Herzog | | SPP | 1, 3, 5 |
| 5. | Mahmood Safi | | SPP | 1, 3, 5 |
| 6. | Jon Shipman | | SPP | 1, 3, 5 |
| 7. | James Simms | | SPP | 1, 3, 5, 6 |
| 8. | Bo Jones | | SPP | 1, 3, 5, 6 |
| 9. | Mo Awad | | SPP | 1, 3, 5, 6 |
| 10. | Derek Brown | | SPP | 1, 3, 5, 6 |
| 11. | Kevin Giles | | SPP | 1, 3, 5, 6 |
| 12. | Jonathan Hayes | | SPP | 2 |
| 13. | Ron Losh | | SPP | 2 |

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 14. Robert Rhodes | | SPP | 2 |
| 15. James Nail | | SPP | 3 |
| 16. Don Schmit | | SPP | 1, 3, 5 |

| | Group/Individual | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 23. | Group | Greg Campoli | ISO/RTO Council Standards Review Committee | | X | | | | | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Cheryl Moseley | ERCOT | ERCOT | 2 |
| 2. Ali Miremadi | CAISO | WECC | 2 |
| 3. Ben Li | IESO | NPCC | 2 |
| 4. Margoth Caley | ISO-NE | NPCC | 2 |
| 5. Terry Bilke | MSIO | MRO | 2 |
| 6. Stephanie Monzon | PJM | RFC | 2 |
| 7. Charles Yeung | SPP | SPP | 2 |

| | Group/Individual | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 24. | Group | Andrea Jessup | Bonneville Power Administration | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Berhanu Tesema | Transmission Planning | WECC | 1 |
| 2. Richard Becker | Substation Engineering | WECC | 1 |
| 3. Don Watkins | System Operations | WECC | 1 |
| 4. Dan Goodrich | Technical Operations | WECC | 1 |
| 5. Ran Xu | Technical Operations | WECC | 1 |

| | Group/Individual | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25. | Individual | Frederick R Plett | Massachusetts Attorney General | | | | | | | | X | | |
| 26. | Individual | John Bee on behalf of Exelon and its affiliates | Exelon | X | | X | | X | | | | | |
| 27. | Individual | Terry Volkmann | Volkmann Consulting, Inc | X | | | | | | | X | | |
| 28. | Individual | shirin.friedlander@ladwp.com | ladwp | X | | X | | X | X | | | | |
| 29. | Individual | Neel Savani | George mason University/ naval Research lab | | | | | | | | | X | |
| 30. | Individual | Barbara Kedrowski | Wisconsin Electric Power Company | | | X | | | | | | | |
| 31. | Individual | Ayesha Sabouba | Hydro One | | | X | | | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 32. | Individual | Andrew Z. Pusztai | American Transmission Company, LLC | X | | | | | | | | | |
| 33. | Individual | Paul Rocha | CenterPoint Energy | X | | | | | | | | | |
| 34. | Individual | Eric Bakie | Idaho Power | X | | | | | | | | | |
| 35. | Individual | Amy Casuscelli | Xcel Energy | X | | X | | X | X | | | | |
| 36. | Individual | Anthony Jablonski | ReliabilityFirst | | | | | | | | | | X |
| 37. | Individual | Jo-Anne Ross | Manitoba Hydro | X | | X | | X | X | | | | |
| 38. | Individual | Si Truc PHAN | Hydro-Quebec TransEnergie | X | | | | | | | | | |
| 39. | Individual | Don Schmit | Nebraska Public Power District | X | | X | | X | | | | | |
| 40. | Individual | Bill Temple | Northeast Utilities | X | | | | | | | | | |
| 41. | Individual | Frederick R Plett | Massachusetts Attorney General | | | | | | | | X | | |
| 42. | Individual | Martyn Turner | LCRA Transmission Services Corporation | X | | | | X | X | | | | |
| 43. | Individual | Johannes Raith | Siemens AG Austria - Transformers Weiz | | | | | | | | | | |
| 44. | Individual | Kayleigh Wilkerson | Lincoln Electric System | X | | X | | X | X | | | | |
| 45. | Individual | Brett Holland | Kansas City Power & Light | X | | X | | X | X | | | | |
| 46. | Individual | Thomas Foltz | American Electric Power | X | | X | | X | X | | | | |
| 47. | Individual | Rick Terrill | Luminant Generation Company LLC | | | | | X | | | | | |
| 48. | Individual | Glenn Pressler | CPS Energy | X | | X | | X | | | | | |
| 49. | Individual | Chris de Graffenried | Consolidated Edison Co. of NY, Inc. | X | | X | | X | X | | | | |
| 50. | Individual | Ayesha Sabouba | Hydro One | | | X | | | | | | | |
| 51. | Individual | Frederick | Emprimus | | | | | | | | | | |
| 52. | Individual | Brenda Hampton | Luminant Energy Company, LLC | | | | | | X | | | | |
| 53. | Individual | John Seelke | Public Service Enterprise Group | X | | X | | X | X | | | | |
| 54. | Individual | Michelle D'Antuono | Ingleside Cogeneration, LP | | | | | X | | | | | |
| 55. | Individual | Oliver Burke | Entergy Services, Inc. | X | | | | | | | | | |
| 56. | Individual | David Thorne | Pepco Holdings Inc | X | | X | | | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 57. | Individual | Karin Schweitzer | Texas Reliability Entity | | | | | | | | | | X |
| 58. | Individual | David Jendras | Ameren | X | | X | | X | X | | | | |
| 59. | Individual | Daniel Duff | Liberty Electric Power LLC | | | | | X | | | | | |
| 60. | Individual | Rich Salgo | NV Energy | | | | | X | | | | | |
| 61. | Individual | George H. Baker | James Madison University | | | | | | | | X | | |
| 62. | Individual | Dan Inman | Minnkota Power Corporative | X | | | | | | | | | |
| 63. | Individual | Mark Wilson | Independent Electricity System Operator | | X | | | | | | | | |
| 64. | Individual | Venona Greaff | Occidental Chemical Corporation | | | | | | | X | | | |
| 65. | Individual | Gul Khan | Oncor Electric LLC | X | | | | | | | | | |
| 66. | Individual | Richard Vine | California ISO | | X | | | | | | | | |
| 67. | Individual | Teresa Czyz | Georgia Transmission Corporation | X | | X | | | | | | | |
| 68. | Individual | Sergio Banuelos | Tri-State Generation and Transmission Association, Inc. | X | | X | | | | | | | |
| 69. | Individual | Joe Tarantino | Sacramento Municipal Utility District | X | | X | X | X | X | | | | |
| 70. | Individual | Russell Noble | Public Utiltiy District No. 1 of Cowlitz County, WA | | | X | X | X | | | | | |
| 71. | Individual | Terry Harbour | MidAmerican Energy | X | | X | | X | X | | | | |
| 72. | Individual | Eric Olson | Transmission Agency of Northern California | X | | | | | | | | | |
| 73. | Individual | Bill Fowler | City of Tallahassee | | | X | | | | | | | |
| 74. | Individual | Angela P Gaines | Portland General Electric Company | X | | X | | X | X | | | | |

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

| Organization | Agree | Supporting Comments of "Entity Name" |
|---|---|---|
| JEA | Agree | FRCC |
| Tennessee Valley Authority | Agree | Planning Standards Subcommittee |
| George mason University/ naval Research lab | Agree | small comment: reference 6 and 21 are identical within Benchmark_GMD_Event_June12.pdf |
| Kansas City Power & Light | Agree | SPP - Robert Rhodes |
| Consolidated Edison Co. of NY, Inc. | Agree | NPCC (Northeast Power Coordinating Council) |
| NV Energy | Agree | PacifiCorp |
| Occidental Chemical Corporation | Agree | Ingleside Cogeneration LP |
| California ISO | Agree | ISO/RTO Council Standards Review Committee |
| Transmission Agency of Northern California | Agree | Sacramento Municipal Utility District |
| City of Tallahassee | Agree | FRCC Regional Entity Committee and Compliance Forum |

| Organization | Agree | Supporting Comments of "Entity Name" |
| --- | --- | --- |
| Colorado Springs Utilities | | Southwest Power Pool (SPP) |
| ladwp | | o The Standard Development Team (SDT) should make it clear that if a responsible entity finds that the GMD Vulnerability Assessment meets the performance requirements of Table 1, it will not have to undertake any Operating Procedures and Mitigating Measures. o LADWP recommends that the Regional Entities review NERC recommendations for modeling, simulation and other related matters, and provide additional guidance to Responsible Entities on modeling, simulation, and potential of GIC in their respective areas, taking into account geography, geology and system topology. Perhaps a regional-wide effort is in order here. |
| Minnkota Power Corporative | | Minnkota supports the NSRF comments |

1. **Organization of the Requirements in TPL-007-1. The SDT has reorganized the standard in response to stakeholder comments. The revised draft is more closely aligned with the steps in the GMD Vulnerability Assessment process. The SDT has also created a flow chart of the overall assessment process. Do these steps address the concerns about the organization of TPL-007-1? If you do not agree or want to provide other recommendations on the organization of the standard please provide specific suggestions in your comments.**

**Summary Consideration:** The drafting team thanks all who commented on the organization of TPL-007. All comments have been reviewed and changes that the SDT supported have been incorporated into the revised version of TPL-007-1 Stakeholders generally supported the organization of the proposed standard. However, the SDT agreed with commenters that suggested reordering the requirement for performing the GMD Vulnerability Assessment and the requirement for establishing System steady state voltage criteria. A summary of comments and the SDT's response is provided below. Some commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here:

- **Respective roles of the TP and PC. Comments suggested that the respective roles be clarified with specific responsibilities assigned for each registered entity to eliminate duplication and confusion.** For the standard to be applicable in all regions, the SDT intends to maintain flexibility as provided in Requirement R1 which specifies each PC, in conjunction with its TPs, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's area. This approach is the same as the one taken in other planning standards.
- **Data requirements. Commenters stated that the standard needed a requirement for entities to provide data to the PC and TP for development of the required models, including specific time requirements such as 'within 90 days'. Some commenters recommended assigning responsibility for maintaining system models to the ERO or its designee.** The SDT believes that requirements for providing modeling data to PCs and TPs are addressed in MOD-032-1 and that an additional requirement in TPL-007 would be redundant. MOD-032 establishes consistent modeling data requirements and reporting procedures for the planning horizon and includes PC, TP, GO, and TO among the applicable entities. MOD-032 also addresses requirements for establishing reporting timelines and for making models available to the ERO or its designee.
- **BES Applicability. Commenters expressed concerns with the draft standard and the revised BES definition. Commenters recommended modifications to the applicability section or to requirements to restrict applicability to BES equipment. A commenter recommended removing the 200 kV threshold in applicability section 4.2 to be consistent with the BES definition.** The SDT acknowledges that parts of the proposed standard apply to non-BES facilities. This is necessary to accurately model GIC since grounded 200kV and higher facilities can impact the GIC calculations. Therefore, Requirement R2 (Maintain System Models) could include non-BES elements that the planner determines are necessary for performing the studies required to complete its GMD Vulnerability Assessment. This applicability is consistent with Order No. 779, which references the "Bulk-

Power System." On the other hand, Requirement R6 applies only to applicable BES power transformers and the SDT has revised the requirement for clarity. Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected transmission system. The 200 kV threshold included in applicability section 4.2.1 is based on analysis indicating that the GIC impact on the network from facilities less than 200kV is minimal due to increased impedance. This analysis is included in the white paper that was developed during stage 1 of Project 2013-03 and available on the project page: http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/ApplicableNetwork_clean.pdf.

- **Reorder Requirements. Commenters suggested that the order would be more logical if the requirement for establishing system steady state voltage criteria preceded the requirement for preforming a GMD Vulnerability Assessment.** The drafting team agrees and has reordered these requirements in the draft standard.
- **Clarification of acceptable evidence demonstrating that agreement has been reached on individual and joint responsibilities (R1/M1).** The SDT revised measure M1 to include the following additional evidence, as recommended: copies of procedures or protocols in effect between entities or between departments of a vertically integrated system.
- **Additional details in the requirements or application guidelines section. Commenters asked for clarification on accounting for storm orientation in GIC studies and recommended that these details be included in the application guideline section. A commenter suggested wording changes to the flow chart in the application guidelines section. Some commenters also stated that the requirements lacked sufficient details of the studies and analysis required.** The SDT understands that studies required for GMD Vulnerability Assessments are new to many in the industry. However, technical guidance provided in the GMD Task Force guidelines and the SDT white papers is expected to enable responsible entities to comply with the standard. Steady state analysis and storm orientation are discussed in Section 2.1.2 of the GMD Planning Guide. A load flow that accounts for GIC flows on the system is performed for each storm orientation. The SDT considered the suggested wording change to the GMD Vulnerability Assessment flow chart but did not believe that the change improved clarity.

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| PacifiCorp | No | PacifiCorp agrees that this model more closely aligns with the GMD Vulnerability process, but the open issues about scope of transformers (Q-7), level of loading (Q-3) and the iterative language in the standard, indicate to PacifiCorp that these issues must be addressed before a decision can be made whether or not to support the current flow chart. |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| Foundation for Resilient Societies | No | We do not agree with the draft standard organization because we believe that the standard does not follow requirements of FERC Order 779, per our other comments. |
| ACES Standards Collaborators | No | (1) We would like to thank the SDT for the inclusion of the GMD Vulnerability Assessment process diagram. However, we still have a concern regarding how the applicable entities are identified in this standard. Requirement R1 has both the PC and the TP concurrently responsible, 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, be the entity responsible for performing the GMD Vulnerability Assessment . Likewise, GICs are not bounded by specific transmission planning areas. Moreover, this addresses the possible confusion which will arise between registered entities and auditors, regarding who is responsible for the requirements of these standards. The SDT should remove each reference to "Responsible entities as determined in Requirement R1" and instead properly assign the appropriate entity based on the responsibilities identified within the NERC Functional Model.(2) We believe the SDT should reconsider the facility criteria in this standard. The SDT should align TPL-007 with the current BES definition that went into effect on July 1, 2014. As written, the standard would appear to be applicable to a 230/69 kV transformer with a wye-grounded high side. However, that transformer does not meet Inclusion I1 of the BES definition and, thus, would not be part of the BES. |
| SERC Planning Standards Subcommittee | No | Is it the intent of the SDT that the entity evaluate the GIC impact of each transformer for each orientation of the Benchmark GMD events (for every 15 degrees from 0 to 90 degrees), and perform a powerflow analysis based on the additional Mvar losses identified for each orientation of the |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| | | Benchmark GMD event?If so, please add these details to the reference material and to the Application Guideline for R3. |
| Ameren | No | We believe that additional clarification is required for the GIC process, and ask about the intent of the standard drafting team to:a. Evaluate the GIC impact of each transformer for each orientation of the Benchmark GMD event (for every 15 degrees from 0 to 90 degrees), and b. Perform a powerflow analysis based on the additional Mvar losses identified for each orientation of the Benchmark GMD event?If so, we request the drafting team add these details to the reference material and to the Application Guideline for Requirement R3. |
| ISO/RTO Council Standards Review Committee | No | Further reorganization is needed. The steady state voltage limits for the System during the benchmark GMD event that responsible entities are required to have under R4 is needed to conduct the GMD Vulnerability Assessment. Accordingly, we suggest that R3 be moved down to become R4 and R4 be moved up to become R3.R1 and R2, in essence, require the development of the necessary models needed to perform the vulnerability assessments. The obligations under those requirements fall on the PC and TPs. However, those functions need data from the equipment owners (GOs and TOs) to develop the models. The standard needs to ensure those entities are obligated to provide the data for this purpose. This can be done in the context of these requirements, or, alternatively, via a stand alone requirement or subrequirement. This data would need to be provided within 90 days of the request, or other agreed to time period.In ISO/RTO regions, compliance with NERC standards is often achieved by performance with regional rules (e.g. ISO/RTO tariff or protocol requirements). Accordingly, M1 should accommodate this approach to demonstrating that the necessary coordination has occurred (i.e. “each Planning Coordinator in conjunction with each of its Transmission Planners”) with respect to |

| Organization | Yes or No | Question 1 Comment |
| --- | --- | --- |
| | | assigning the relevant responsibilities. Footnote 1 from NUC-001 may be informative for this purpose. Specifically, FN 1 states:1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system. |
| Hydro-Quebec TransEnergie | No | The reordering of requirements following the consecutive steps is improving the standard. However, the GMD Vulnerability Assessment in requirement 3 needs clarification. First, it would be helpful to refer to Table 1 for this Assessment. Second, it is not clear what Assessment needs to be done. How could this event of increased dc current on the system analysed in steady state cause the transformer saturation and then the removal of compensating devices or Transmission Facilities ? How is one going to analyze the effects of harmonics on the tripping of protection systems ? The diagram in Attachment 1 is a good start, but it should be developed more to clarify all those elements. |
| Northeast Utilities | Yes | Consider redrafting the note at the end of the flow chart from “Operating Procedures and Mitigations Measures (if needed)” to say “Operating Procedures and Mitigation Implementation Actions (if needed)”. |
| James Madison University | No | |
| Ingleside Cogeneration, LP | Yes | Ingleside Cogeneration LP (ICLP) agrees that it is the initial responsibility of the Planning Coordinator and/or Transmission Planner to identify transformers that may be vulnerable to GMD. They have the system models and simulation engines that can best make that determination. Once the PC/TP analysis is complete, only those GOs and TOs who own susceptible components will be responsible for a comprehensive thermal analysis - again a sensible expectation. After all, it is in the owner’s best interest to protect valuable equipment if there is a tangible threat posed by |

| Organization | Yes or No | Question 1 Comment |
| --- | --- | --- |
| | | GMD. Conversely, those located in areas that are not at risk should not be required to spend scare dollars and resources preparing for a very low-probability event. |
| Georgia Transmission Corporation | Yes | GTC agrees that the flowchart addresses the steps for the overall assessment process. We would like the SDT to consider adhering to the current BES definitions for facilities. As non-BES facilities could be subjected to this standard. |
| Associated Electric Cooperative, Inc. - JRO00088 | Yes | |
| Northeast Power Coordinating Council | Yes | |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | Yes | |
| Arizona Public Service Company | Yes | |
| Dominion | Yes | |
| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| Colorado Springs Utilities | Yes | No Comments |
| Bureau of Reclamation | Yes | |
| Duke Energy | Yes | |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| MRO NERC Standards Review Forum | Yes | The NSRF agrees that the steps in the revised draft for TPL-007-1 address concerns about the organization of the standard. We would like to commend the SDT for paying attention to the recommendation of stakeholders by developing the flowchart and a process that is sensible and easy to follow. |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | |
| PPL NERC Registered Affiliates | Yes | These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. |
| SPP Standards Review Group | Yes | |
| Bonneville Power Administration | Yes | |
| Massachusetts Attorney General | Yes | |
| Exelon | Yes | |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| Volkmann Consulting, Inc | Yes | |
| ladwp | Yes | |
| Hydro One | Yes | |
| American Transmission Company, LLC | Yes | |
| CenterPoint Energy | Yes | |
| Idaho Power | Yes | |
| Xcel Energy | Yes | |
| Manitoba Hydro | Yes | The revised organization is an improvement - no concerns. |
| Nebraska Public Power District | Yes | |
| LCRA Transmission Services Corporation | Yes | |
| American Electric Power | Yes | |
| Luminant Generation Company LLC | Yes | |
| Hydro One | Yes | |
| Emprimus | Yes | |
| Luminant Energy Company, LLC | Yes | |
| Public Service Enterprise Group | Yes | |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| | | |
| Entergy Services, Inc. | Yes | |
| Pepco Holdings Inc | Yes | |
| Texas Reliability Entity | Yes | |
| Liberty Electric Power LLC | Yes | |
| Minnkota Power Corporative | Yes | |
| Independent Electricity System Operator | Yes | |
| Oncor Electric LLC | Yes | |
| | | |
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| MidAmerican Energy | Yes | |
| DTE Electric | | No Comment |
| Public Utiltiy District No. 1 of Cowlitz County, WA | | Cowlitz defers to the Planning Coordinators and Transmission Planners. |

2. **Benchmark GMD Event. The SDT has provided additional guidance in TPL-007-1 Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event). Changes include how a planning entity with a large geographic area can handle scaling factors in the planning area, and specific guidance on earth conductivity scaling when the planning entity does not have a ground conductivity model. During informal comments, many commenters indicated that they agreed with the proposed benchmark GMD event and no substantive changes have been made. Do you agree that the guidance in TPL-007-1 Attachment 1 provides the required details for applying the proposed benchmark GMD event? If you do not agree or have additional new comments on the proposed benchmark GMD event, please provide specific technically justified suggestions for the SDT to consider.**

**Summary Consideration:** The drafting team thanks all who commented on the benchmark GMD event. All comments have been reviewed and changes that the SDT supported have been incorporated into the revised version of TPL-007-1 and supporting white papers. A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections.

- **Scaling factors for large geographic areas. Several commenters did not agree with the SDT's approach or requested additional technical information on applying scaling factors to planning areas that span more than one latitude or geophysical area. A commenter asked for information on the availability of tools that were capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field as stated in Attachment 1.** The SDT has clarified TPL-007-1 Attachment 1. The statement now reads: "For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field." A similar statement in Attachment 1 provides guidance to address the geomagnetic latitude scaling factor alpha in a large area. Commercial tools can assign different geoelectric fields (V/km) to different parts of the system on the basis of different scaling factors. This is a reasonable approximation for the use of a non-uniform geoelectric field. The statement "Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field." is intended to permit utilities with more sophisticated tools to use them, and to allow for application of future developments in commercial GMD analysis software.
- **Effective GIC. A Commenter stated that Effective GIC should be explicitly defined.** Effective GIC is defined in the white papers and in the NERC GMDTF Application guide.
- **Determining geomagnetic latitude and the geomagnetic latitude scaling factor. A commenter stated that Figure 1 in Attachment 1 lacks precision, and that the equation for the scaling factor alpha in attachment 1 provides a more precise value than Table 2.** The figure is intended for illustration purposes only. The SDT agrees that it is better to either use-geophysical software or calculators provided in one of a number of web sites such as: http://omniweb.gsfc.nasa.gov/vitmo/cgm_vitmo.html

- **Earth models. A commenter stated that the standard does not specify criteria for a technically-justified earth model to be used as a substitute for attachment 1 Table 3.** The SDT modified Attachment 1 to more clearly indicate that a responsible entity may use a specific earth model(s) with with documented justification.
- **Technical justification for the geomagnetic waveshape. A commenter stated that the justification for using the March 1989 event did not conclude that this was the worst case waveshape; and that they disagreed with assumptions of transformer thermal effects without testing of multiple designs.** The SDT has provided justification for using this waveshape in thermal assessments. The white paper shows that it is conservative from thermal assessment point of view when compared to other major GMD events. The SDT's assumptions about transformer heating are consistent with published technical literature.
- **Earth conductivity scaling factor validity. A commenter stated that the scaling factors did not account for proximity to salt water bodies. Another commenter stated that GIC data measured in two stations located in coastal areas do not match calculations made with USGS earth models.** The geoelectric field scaling factors in Attachment 1 do not include costal effects because they reflect average earth models available from USGS and NRCan. The standard does not preclude an entity from using more detailed earth models and including geoelectric field enhancements or coastal effects at the edge of salt water bodies.
- **Geomagnetic latitude scaling validity. Commenters questioned the technical basis for alpha scaling factors.** As indicated in the Benchmark GMD Event white paper, the alpha scaling factors are based on global geomagnetic field observations of 12 major or extreme geomagnetic storms since the late 1980s (Thomson et al., 2011; Pulkkinen et al., 2012; Ngwira et al., 2013). For all observed storm events, the maximum expansion of the auroral region was identified and the corresponding time derivatives of the ground magnetic field (dB/dt) or geoelectric field magnitudes were computed. The approximate factor of 10 fall of the dB/dt and associated geoelectric field magnitudes between geomagnetic latitudes from 60 degrees to 40 degrees represent the general trend that was observed for all studied storm events at the time of the maximum expansion of the auroral region. In summary, the selected geomagnetic latitude scaling is based on global geomagnetic field observations of major or extreme storm events and represents approximate field scaling at the time of the maximum expansion of the auroral region.
- **Validity of the method used to generate geoelectric field scaling factors. A commenter stated that the plane wave method used to calculate geoelectric fields from geomagnetic field data produces incorrect results and it systematically produces low geoelectric field values.** The plane wave method that was utilized in the generation of the NERC GMD benchmark event has been applied extensively in GIC studies over the past several decades. The method has been shown in numerous studies to accurately map the observed ground magnetic field to the geoelectric field and observed GIC (e.g., Trichtchenko et al., 2004; Viljanen et al., 2004; Viljanen et al., 2006; Pulkkinen et al., 2007; Wik et al., 2008). Further, although the plane wave method assumes a one-dimensional (1D) ground conductivity structure, the method has been shown to be applicable even in highly non-1D situations if an effective 1D ground conductivity is used (Thomson et al., 2005; Ngwira et al., 2008; Pulkkinen et al. 2010). **The same commenter showed an example comparing the geoelectric field calculated using a USGS model and the geoelectric field**

**estimated from GIC measurements and stated that calculations using USGS models will consistently result in lower peak maxima.** Comparisons with measured data are valuable tools to validate and improve earth models. There are efforts in the industry to validate and adjust average earth models on the basis of GIC and magnetometer measurements. This type of validation has to be done carefully in order to avoid numerical issues caused by using data with different sampling rates and thus mask differences due to inaccuracies in the earth model to be validated. The example presented by the commenter used downsampled 1 minute geomagnetic field data from the OTT geomagnetic observatory on May 4 1998 to calculate the geoelectric field from the "NERC" model. When the same calculations are carried out using 5 second geomagnetic field data from the same observatory, calculated geoelectric field peak maxima increase by a factor of 1.5 to 1.9. The use of 1 minute magnetometer data will always result in lower calculated peak maxima.

- **Technical justification and methods for determining the benchmark GMD event. Some commenter did not agree with the application of magnetometer data from Europe to determining the benchmark, or with the spatial averaging technique described in Appendix I of the Benchmark GMD Event white paper. A commenter did not support a 100-year benchmark or including specific engineering margin in the benchmark, while others commented that the margin was too high or too low. Commenters argued for basing the benchmark event on other information such as EPRI SUNBURST data, or on an entity's own local magnetometer data.** The SDT developed a consistent benchmark for application across the Bulk-Power System as outlined in the Standard Authorization Request and Order No. 779. Allowing entities to establish their own benchmark will not achieve the objectives outlined in the SAR and FERC Order. The SDT believes a 100-year benchmark is appropriate due to the broad geographical scale inherent in a major GMD event. A data set of high resolution modern magnetometer observations that has been used extensively in space weather research was used in the benchmark analysis. The SDT maintains that spatial averaging is supported by the magnetometer data and justified for determining the wide-area impacts on the power system. The North American magnetometer network is too sparse to be used as the basis of spatial averaging. Nevertheless, the statistical storm peaks recorded in North America are consistent with those recorded in Europe. The spatially-averaged uniform geoelectric field assumption takes into consideration wide-area geoelectric field values. Data used to determine the benchmark thresholds are spatially averaged, not time averaged. Data in Figure I-2 of the benchmark definition white paper reflect only event peak event values. It is not based on the assumption that 3 V/km represents some kind of sustained average value while 8 V/km represents a 10s duration peak.
- **Multiple benchmarks and alternate approaches. A commenter recommended a 3 V/km benchmark for performance requirements and an 8 V/km benchmark for studies only. A commenter recommended an alternate approach requiring GIC monitoring and hot-spot monitoring to calibrate models.** The SDT agrees that earth models need to be validated and possibly modified on the basis of recorded GMD events. There are a number of initiatives in place to do precisely that. There are however, some difficulties in the approach proposed: Hot spot measurements can only be carried out when the unit is instrumented in the factory and placed in service with appropriate data acquisition provisions. Recorded GIC can only be

validated against an earth model when geomagnetic field measurements are made at the same time. Efforts are underway to increase the number of magnetic field measurements in North America for this purpose. Initiatives to validate earth and transformer thermal models will take years.

- **Margin estimation. A commenter indicated that adding a margin to extreme value analysis results to arrive at 8 V/km is unrealistically conservative.** The SDT has used extreme value analysis to support the extrapolation to a 1 in 100 year frequency in Figure I-2 of the GMD benchmark event white paper. Stating that an engineering margin was added to the results of extreme value analysis is inaccurate and the text in white paper has been modified accordingly.
- **Concerns with specific ground models referenced in TPL-007 Attachment 1. Commenters stated that the standard should not be applicable to entities in Florida without further justification of the proposed scaling factor. Commenters questioned validity of ground models in some areas.** NERC has highlighted the need for a Florida earth model with USGS and other research organizations and several efforts are underway that are expected to fill this gap within the implementation timeline for TPL-007. USGS has responded by producing a preliminary earth model for Florida (CP3), and the corresponding scaling factor has been added to Table II-2 of the GMD benchmark white paper and to Table 3 of Attachment 1. The SDT wants to reiterate that the scaling factors represent the current knowledge on the basis of the average earth models available from USGS and NRCan. The standard allows the use of technically justified earth 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.
- **Peer Review. A commenter recommended NERC initiate a peer review to satisfy OMB guidance. A commenter questioned the adequacy of review by space weather experts.** Although this OMB bulletin does not apply to NERC, NERC uses peer-reviewed research to the maximum extent possible.
- **Implementation with a technical evaluation. A commenter asked about pilot evaluations of the GMD assessment process and recommended a pilot project.** A number of GMD studies have been carried out in US and Canadian utilities using the evaluation methods required in the standard including a number of utilities in the NERC GMD Task Force. The Standard is responsive to the FERC order and is based on technical work of the GMD TF. The proposed phased approach for implementation provides similar benefits to a formal pilot project.

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| PacifiCorp | No | Please refer to PacifiCorp’s responses to Q-3 and Q-7. While Attachment 1 is a well written document, it does not provide enough detail to adequately address the multiple variables in a multi-state area for large entities that (1) are not currently familiar with the technical applications of the soon-to-be-developed software and (2) |

| Organization | Yes or No | Question 2 Comment |
| --- | --- | --- |
| | | cover a large geographic area. "Additional guidance" concerning applying the benchmark event is now in Appendix 1 of proposed TPL-007-1. Specifically, Appendix 1 now addresses how a planning entity with a large geographic can handle scaling factors and for both scaling factors suggests:"For large planning areas that cover more than one scaling factor....the most conservative (largest) value for Î± should be used in scaling the geomagnetic field. Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field." See Appendix |
| Associated Electric Cooperative, Inc. - JRO00088 | No | AECI has concerns with the selection of a beta value for planning areas that span more than region. The issue was addressed at the technical conference, however statements were somewhat contradictory to what is described in Attachment 1. AECI requests additional clarification on the following language included in the standard: "Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field". What tools are available to perform this? In the technical conference, "engineering judgment" was stated as acceptable but the language does not support this broad of a method and guidance does not describe a specific method for performing the calculation. Without direction on this alternative method, AECI would be forced to use a most conservative value which would not appropriately represent our area. Table 1 - Footnote 4: AECI believes that it would be acceptable to use load shed or curtailment of service as a primary method of achieving required performance, if the MW value of load or service does not exceed a maximum threshold. AECI requests the SDT consider revising language to allow for such a solution to be considered primary when reasonable. |
| Northeast Power Coordinating Council | No | Attachment 1 - A definition of and method for calculating "Effective GIC" should be explicitly provided. The use of different definitions and approaches due to a lack of standardization in adjacent regions could become problematic. A standardized approach would help to prevent different computational approaches, differing model |

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| | | results, and conflicting Corrective Action Plans (CAPs). Thus, it is important that the method for calculating "Effective GIC" be provided. The Transformer Mvar Scaling Factors used in PSSE are based on a paper published by X. Dong, Y. Liu, J. G. Kappenman, "Comparative Analysis of Exciting Current Harmonics and Reactive Power Consumption from GIC Saturated Transformers", Proceedings IEEE, 2001, pp 318-322.Determination of geomagnetic latitude provided in Attachment 1 lacks clarity and precision. Figure 1 provided for this purpose may be used for very rough approximation only. The determination of geomagnetic latitude table in Attachment 1 is an approximate guide to determine the geomagnetic latitude of a given network. More accurate determination of geomagnetic latitude can easily be determined with a number of publicly available tools. Also, geomagnetic latitude changes over time, which may not be reflected by this static picture. Better results may be obtained by directing users to NOAA link: http://www.swpc.noaa.gov/Aurora/globeNW.htmlThe geomagnetic field factor alpha in Table 2 in the Appendix should also be viewed as an approximation of alpha factors more readily calculated with the equation in Attachment 1. The geomagnetic field factor alpha accounts for regional differences and provides a floor from which applicable entities can expand if needed. This scaling factor can also be used to approximate non-uniform geoelectric fields in a geographically large service territory in steady-state calculations.The selection of 8 V/km is a reasonable compromise for a 100 year return event, as suggested by the FERC order. It is difficult to characterize a wide area system event by a single peak in a geographically confined local geoelectric/geomagnetic field enhancement. Although the value is primarily based on magnetic field measurements in Europe because such measurements are sparse in North America, it is consistent with the historical values measured in from North America. With additional measurements over time, a better value may be obtained. The 8 V/km is the best possible estimate at this time with the available data. The extreme value analysis provided in the GMD benchmark white paper provides mathematical rigor. From an engineering point of view it makes more sense to for spatially-averaged values to be used to assess wide- |

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| | | area impact, as opposed to 20 V/km estimate when only storm peaks were considered in the 2012 NERC GMD interim report. |
| Foundation for Resilient Societies | No | Comments on Attachment 1, “Calculating Geoelectric Fields for the Benchmark GMD Event”1. The draft standard does not state the criteria for a “technically justified earth model” to be used as a substitute for the USGS model.2. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveshape to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment. The Standard Development Team does not present any evidence that this waveshape would be a “worst case” waveshape, only an assertion that this is a “conservative” waveshape for thermal analysis.3. The geoelectric scaling factors do not include an adjustment for transformers located at the edge of water bodies.Comments on Benchmark Geomagnetic Disturbance Event Description1. We do not agree with the statement, “Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.” Without testing of multiple transformer designs, this is an assertion not supported by statistically valid evidence.2. We do not agree with the statement, “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 in order to avoid bias caused by spatially localized geomagnetic phenomena.” A severe but localized event could still cause a cascading outage if it is unexpected.3. Despite the statement, “any benchmark event should consider the probability of occurrence of the event and the impact or consequences of the event,” the Benchmark GMD Event does not incorporate safety factors consistent with the consequences of the event.4. The Benchmark GMD event modeling  is based on magnetometer data but not validated with actual GIC measurements at a variety of latitudes and earth resistivities. NERC should not use an unvalidated model when millions of lives are at stake and when GIC |

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| | | data exists at EPRI SUNBURST and elsewhere to validate (or invalidate) the NERC model.5. The “Hotspot” hypothesis for geoelectric field maximums is not adequately supported by observatory data for North America. If NERC wishes to promote this hypothesis, it should be required to show that magnetometer observatory data does not move in tandem across wide areas of North America.6. It is not prudent to use a limited period of January 1, 1993 - December 31, 2013 to predict a maximum geoelectric field of 8 volts/km that may occur with a frequency occur over hundreds of years.7. The maximum geoelectric fields produced by the NERC statistical model for a severe solar storm (1-in-100 years) are at or below the fields and/or GIC measured in North America for moderate solar storms. Therefore, the NERC statistical model must be wrong. See comments of John Kappenman in this NERC comment period.8. The section “Impact of Local Geomagnetic Disturbances on GIC” is speculative and unsupported by actual data and experience. It relies on an unproven “hotspot” hypothesis.9. IN “Appendix II - Scaling the Benchmark GMD Event” there is no scaling for a transformer being adjacent to a body of water when research shows that this adjacency increases GIC. |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | No | Scaling Factor for FRCC RegionThe FRCC RECCF believes that the Standard Drafting Team (SDT) should not move forward until a technical basis is developed for the scaling factor for the FRCC Region.At this time, the SDT has acknowledged that a scaling factor for the FRCC Region does not appear to have been developed as part of the supporting documentation for this Standard. In the alternative, the SDT has selected the value of 1.0 for a scaling factor, however, the SDT has not published any data as to how this value was determined. Without any technical justification supporting the currently proposed value of 1.0, the FRCC RECCF argues that this value was selected merely because it is a round/whole value, and that it is devoid of any technical analysis to the effect the other Regions were studied. If this value, or any other value, continues to be proposed without any technical justification, the FRCC RECCF may argue that this value is “arbitrary and capricious” under 5 U.S. Code Â§ 706(2)(A). Therefore, the FRCC RECCF requests that the SDT delay any further |

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| | | proposals until a technically justified factor is developed. In the alternative, the FRCC RECCF requests that the FRCC Region be excluded from the rulemaking until a factor is technically justified.Cost Analysis The FRCC RECCF would like to see a cost analysis performed for this proposed standard. As described in a later comment, the FRCC RECCF would prefer a CEAP performed for this Standard. The FRCC RECCF reasons that this Standard will be costly and that the benefits are vague for the FRCC Region, and therefore requests that a cost-to-benefit analysis be performed for each specific NERC Region. The FRCC RECCF prefers the CEAP process to a separate process, such as a request to the Government Accountability Office to assist in a cost benefit analysis, and therefore requests that the SDT commence immediately on developing a CEAP. In support of this request the FRCC RECCF 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 and included as an attachment herein.Peer Review The FRCC RECCF requests that NERC coordinate a peer review of the scientific information that is being utilized for the basis of this rulemaking in accordance with the Office of Management and Budget’s December 16, 2004 Bulletin that “establishes that important scientific information shall be peer reviewed by qualified specialist before it is disseminated by the federal government.” This Bulletin directs federal agencies to perform peer reviews of influential scientific information before it is fully disseminated, e.g., through a FERC NOPR. TPL-007-1 is an ideal example of a regulatory action based on scientific assessments that is covered by this Bulletin. Although NERC is not a federal agency, it is performing the review and development of rules in FERC’s place to an extent, and so NERC, in coordination with FERC, should be tasked with the peer review of any influential assessments that NERC is relying on as a basis for the proposed Standard. If NERC does not perform this review and the this Standard is eventually sent to FERC for approval, FERC’s rulemaking ability may be hindered to a great extent if a peer review process has to be initiated at that later stage rather than being performed at the NERC rule development stage.Therefore, |

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| | | the FRCC RECCF believes that NERC should immediately initiate a peer review of any influential scientific assessments in accordance with the Bulletin that the SDT is relying upon. |
| Colorado Springs Utilities | No | We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. What pilot evaluations have been completed to vet this process with the selected event? We would recommend rolling this process out in a pilot format to refine it and ensure that we are getting the desired evaluation that improves reliability prior to wholesale enforcement. Pilots would need to be conducted in various geographical areas and companies. Then results would be compared and processes refined to reach our reliability goals. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. 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. |
| MRO NERC Standards Review Forum | No | The NSRF has a concern in reference to how and when we should use the Beta value in scaling the geoelectric field. Per the discussion at the July Technical Conference, it was suggested that “engineering judgment” should be used in this process. However; the standard suggest ‘For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for Î² should be used in scaling the geoelectric field.’ We would like to see more clarity on how Beta should be used in the calculation process and suggest implementing the term ‘engineering judgment’ into the standard.Also, we are concerned that data in Table II-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the IP1 earth model. The Benchmark GMD Event is represented by the SHIELD region on Figure II-3: Physiographic Regions of North American and the Geoelectric Field Scaling Factor is 1.0. The one reading for the IP1 earth model is measured relatively close to |

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| | | the SHIELD and the scaling factor is 0.94. However the IP1 model includes a very large portion of the US map. The NSRF believes that this scaling factor is inappropriate and is not representative of all the US regions included in the IP-1 earth model particularly the lower parts of the region such as the state of Iowa that exhibits low resistivity that the 0.94 scaling factor is clearly too high. We recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference. |
| SPP Standards Review Group | No | We have a concern in reference to how and when we should use the Beta value in scaling the geoelectric field. Per the discussion at the July Techincal Conference, it was suggested that 'engineering judgement' should be used in this process. However; the standard suggest 'For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for Î² should be used in scaling the geoelectric field.' This seems contradictory to what was expressed at that Technical Conference. We would like to see more clarity on how Beta should be used in the calculation process and suggest implementing the term 'engineering judgement' into the stardard. |
| Volkmann Consulting, Inc | No | SDT has not adequately justified the size of the peak E-field area, nor has provided gudiance as to how analyze the area if so chosen by the PC or TP. |
| Manitoba Hydro | No | 1. Canadian entities do not benefit from the proposed scaling factor proposed for southern latitudes. The 8 V/km includes an arbitrary reliability margin on top of an event that already has a probability of occurrence of 1/100 years. The current NERC standards have four categories of events with varying levels of probability. A category C is the lowest probability event that requires a corrective action plan when performance requirements are not met. Category C events are generally recognized as having a 1/10 year probability (eg. breaker failures). A suggested improvement is to allow entities that have their own local magnetometer data to use the worst case(s) found since the 1989 event in Quebec as their benchmark GMD event. Those |

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| | | entities should then also describe where they include reliability margin in their analysis. One example might be to assume that the reactive power loss from all of their transformers are from single phase transformers rather than three-legged core, for example. 2. FERC Order 779 does not specify what the severity of the Benchmark GMD event should be. Paragraph 71 of Order 779 states the benchmark should be technically sound. Similar standards such as IEC 60826 have a minimum reliability design requirement of 1-in-50 and suggest higher reliability levels can be used if justified by local conditions. What is the basis and justification for selecting a 1-in-100 year event over say a 1-in-50 year event or a 1-in-200 year event? 3. Two references provided to support the benchmark GMD event, "Generation of 100-year geomagnetically induced current scenarios", Space Weather Vol.10, 2012, Pulkkinen, et al and "Credible occurrence probabilities for extreme geophysical events: Earthquakes, volcanic eruptions, magnetic storms", Geophysical Research Letters Vol 39, 2012, Love, provide strong evidence that the March 1989 GMD event has an occurrence rate of approximately 1-in-50 years (well in agreement other extreme events such as wind and icing etc.). Why develop a hypothetical benchmark event when a reasonable and known event already exists? 4. Page 5 of the NERC "Benchmark Geomagnetic Disturbance Event Description" states:"The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years... The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used..."It is extreme to consider that the frequency of occurrence for a 1 in 100 year event is consistent or equivalent with the frequency of occurrence for a 1 in 50 year event. What is the technical basis/justification for this statement?5. Figure 2 and Figure 3 of the NERC "Benchmark Geomagnetic Disturbance Event Description" illustrate the time series of the geoelectric field wave shape for the benchmark GMD event. From these plots it is clear that there is only one spike peaking at the 8V/km field intensity over the 24 hr period displayed. Pages 8 and 9 of the NERC "Benchmark Geomagnetic Disturbance Event Description" provide arguments that the benchmark is designed to stress wide-area effects caused by a severe GMD event. Please provide evidence that these |

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| | | characteristic peaks or spikes in geoelectric field measurements are a global phenomenon rather than a local phenomenon.6. Page 13 last paragraph of the NERC “Benchmark Geomagnetic Disturbance Event Description” incorrectly states that a 25% engineering margin is added to the extreme value return level of 5.77 V/km. Note that 8/5.77 = 1.386 so in truth a 39% engineering margin was added to the 100-year return level. 7. The NERC “Benchmark Geomagnetic Disturbance Event Description” seems overly pessimistic base on the number of “fudge factors” or “engineering margins” added due to assumptions in its development. Please quantify the level of engineering margin added for each of the five assumptions made in developing the benchmark event. The five assumptions are identified below:a. Figure 2 and Figure 3 of the NERC “Benchmark Geomagnetic Disturbance Event Description” shows a typical GMD is an event where the geoelectrical field is changing both magnitude and direction relatively slowly over time. Such phenomena are classified as “quasi DC” or “slow transient” yet we simulate this event as more pessimistic steady state phenomena. In addition the reference, “Saturation Time of Transformers Under dc Excitation”, Electric Power Systems Research , 56, 2000, Bolduk et al, provided to support the benchmark GMD event suggests that there is some time delay before the transformer responds to the GIC (seconds to minutes depending on the transformer). Using steady state analysis to simulate slow transients basically implies that we are assuming that the maximum geoelectric field intensity is applied permanent. What is the engineering margin added by this steady state assumption?b. The benchmark event described in the NERC “Benchmark Geomagnetic Disturbance Event Description” is assumed to represent a uniform geoelectric field in both magnitude and direction over a large area when in reality the geoelectric field is not uniform over a larger area. (In fact by using geoelectric field plots for large area such as that in Figure I-1 one can easily argue that the assumption of a large scale uniform electric field in both magnitude and direction is invalid, that over the wide scale the geoelectric field is in fact non-uniform in both magnitude and direction. The assumption of a uniform electric field in both magnitude and direction is only valid over the small scale). What is the engineering margin added by the uniform |

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| | | geoelectric field assumption?c. For a given utility, the analysis (which as stated is to address wide area effects caused by GMD) requires a uniform geoelectric field in the north-south direction. A utility with a large north-south extent will select the worst case north-south geoelectric field defined by the northern most point of their system. This will result in ignoring the north-south geoelectric field reduction scale factor. What is the engineering margin added by this unscaled north-south geoelectric field assumption?d. While not directly stated Figure I-2 in the NERC “Benchmark Geomagnetic Disturbance Event Description” is derived by spatially averaging the data used to generate Figure 2b in reference “Statistics of extreme geomagnetically induced current events”, Space Weather Vol 6 2008, Pulkkinen et al. On page 3 of Pulkkinen et al tell us how to interpret Figure I-2. Simply put Figure I-2 tells us the number of 10 second measurement intervals that can in principle occur during one extreme storm with the specified geoelectric field magnitude (x-axis). Based upon Pulkkinen et al interpretation of their data, Figure 2, Figure 3 and Figure I-2 in the NERC “Benchmark Geomagnetic Disturbance Event Description” implies that in practice the worst case spike in the geoelectric field can be characterized for example by a 10 second duration transient peak at 5.77 V/km and a steady state 5 minute duration of 3 V/km main body. Choosing the short duration peak geoelectric field over some time averaged longer duration geoelectric field for the steady state analysis means that we are assuming that the peak geoelectric fields is applied permanently on the system rather than a more reasonable “time averaged” longer duration value. What is the engineering margin added by in assuming the steady state geoelectric field is represented by the transient peak value assumption?e. The extreme value analysis predicts that the maximum return value for the geoelectric field in the 1-in-100 year event is 5.77 V/km. A 39% engineering margin is added to scale that level up to 8 V/km.8. Based upon the engineering margins identified in 7a through to 7d above please provide technical justification why the additional 39% engineering margin is required in 7e. |

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| Hydro-Quebec TransEnergie | No | The benchmark GMD Event is a new approach that needs to be well mastered before being adopted. Hydro-QuÃ©bec TransÃ‰nergie is concerned with the Benchmark GMD Event proposed in Attachment 1 and the high value of the geoelectric field of 8 V/km: o The value is not based on direct measurement of E, but it is deduced from B. The link between both measurements is not always linear and the relation is complex because they are not plane waves. E readings do exist and they should be considered directly in this evaluation of a GMD Benchmark. o The data comes from European values translated and adapted to the North American situation, but without considering local geomagnetic field, which are part of the polar and sub polar areas. o The B field should not be considered uniform, especially for a very wide area. o The maximum statistical data of E field during 167 months is under 3 V/km, which did happen only 7 times for a total time of less than two minutes. The 8 V/km is too pessimistic value and real historical American or Canadian values should be reconsidered. Since the approach is recent and is based on many assumptions mentioned, and because an eventual assessment may bring corrective actions with surprisingly high costs, it is proposed to adopt a prudent approach with regards to compliance. We propose that compliance could be completed with two levels as it is done in TPL-001-4, such as basic Planning Performance Requirements and Performance in Extreme Events. Applicable Entities would have to comply with the performance requirements of the first category, but they would only need to do the evaluation of possible actions to reduce the likelihood or mitigate the consequences for the second category. Such an approach could be applied in TPL-007-1. The application could be done on two different GMD benchmark: 3 V/km for the first category, and 8 V/km for the second category. We think this could be very helpful for the compliance of such a new approach. |
| Nebraska Public Power District | No | We have major concerns on the Beta value in scaling the geoelectric field. Per the discussions at the July Technical Conference, it was brought up that between the IP1 and IP2 conductivity regions the difference between beta values is extremely large (0.94 versus 0.28). The task force formal response was to utilize the highest beta |

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| | | value for the study area which involved both of these regions. This results in the study being extremely conservative and increases the risk that unnecessary mitigations could be required. To address this issue, we request that the Standard Committee provide more detailed conductivity maps with additional conductivity regions to address where abrupt changes between conductivity regions as they exist now. In addition, we request that the Standard Committee provide additional guidelines on how the geoelectric field is calculated with a transmission line being split between two different conductivity regions. For example, is it acceptable to base the geoelectric calculation on a percent line length in each conductivity region? In addition,it is recommended the standard specifically include provisions that Engineering judgment is allowed to calculate realistic geoelectric values in a large study area. |
| Lincoln Electric System | No | How should the Beta value be used to scale the geoelectric field? The standard states 'For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for Î² should be used in scaling the geoelectric field.' For example, using the largest value for Î² for the state of Nebraska results in using the value for IP1 instead of IP2 although 80% of the state resides within the IP2 region. Furthermore, a planning area that uses the largest value for Î² may result in adjacent planning areas in the same region using different values for Î². To account for this issue, LES suggests modifying the standard to allow for the use of engineering judgment when determining the value for Î². |
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| MidAmerican Energy | No | MidAmerican is concerned that data in Table II-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the IP1 earth model. The Benchmark GMD Event is represented by the SHIELD region on Figure II-3: Physiographic Regions of North American and the Geoelectric Field Scaling Factor is 1.0. The one reading for the IP1 earth model is measured relatively close to the SHIELD and the scaling factor |

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| | | is 0.94. However the IP1 model includes a very large portion of the US map. This scaling factor is inappropriate and is not representative of all the US regions included in the IP-1 earth model particularly the lower parts of the region such as the state of Iowa that exhibits low resistivity that the 0.94 scaling factor is clearly too high. MidAmerican recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference. |
| Emprimus | No | Response to NERC Draft Benchmark GMD Event Description - Under FERC Order 779 By Dr. Frederick Faxvog, Gale Nordling, Greg Fuchs, David Jackson, Wallace JensenExecutive SummaryFERC, in Order 779, requires NERC to develop “technically justified” benchmark GMD events upon which utilities will use as a basis to protect their grid. Utilities, NERC, FERC and the professional engineers working for them have a moral, fiduciary and legal obligation to protect the public health, welfare, and customer service through the adoption and implementation of GMD standards that have integrity and that are well vetted by multiple space weather and electric power professionals. NERC is now introducing, in response to FERC Order 779, a new untested and unverified low level benchmark GMD model which greatly reduces the GMD electric field which the utilities need to protect against. This brand new, unvetted theory, absent significant study, peer review and peer consensus, should not be transformed into a standard which is supposed to protect the health and safety of 100’s of millions of Americans.This new model has come up with geo-electric fields that are so much lower than the standards currently for which there is consensus (for a 100 year severe solar storm), that it is being challenged for credibility and reasonableness by many technical experts. This alone should lead one to conclude that a more rigorous peer review and peer consensus of the model is warranted.This proposed new model could lead utilities to conclude that there is no real threat of damage from GMD, and that they need to do little or nothing additional to comply with it. However when the next significant solar storm hits and significant grid outages occur, and loss of life and substantial financial impact occur, there will |

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| | | be outcry from the public that leads to scrutiny of this model and the process that was used to review it and approve it. The dissenting voices that are skeptical of the incredibly low predicted outcomes of a GMD event will certainly be highlighted in any kind of investigation. We urge caution in considering the adoption of a new standard, without peer consensus, that might be interpreted as self-serving, especially if it is not properly drafted and vetted widely (with consensus) by experienced space science professionals as required by ANSI standards. In addition, the potential lack of protection for customers by using a much lower standard, based upon a completely new unproven and unvetted theory, could expose the utilities to claims. This is another reason to hold a more rigorous review of the model before submitting it for approval.In this paper technical experts at Emprimus who have a corporate focus on protecting the grid from EMP and GMD, have done an analysis of the new NERC benchmark model. The Emprimus conclusions start with identifying the need to do an extensive peer review by space science experts in the GMD community and ensure that the new standards follow the ANSI standards. Additional points include the need to address worst case scenarios versus just addressing the average impacts; the hot spot analysis is not technically justified; the wave form analysis is not technically justified; the "latitude reduction" theory is highly questionable; the assumptions about probability of occurrence of solar super storms are not supported by GMD experts; the known impact to customers and generators from harmonics are not addressed; the substantial increase in grid vulnerability due to power transfers and contingencies has not been taken into consideration; and the magnitude of the impact to customers and national security has not been factored in as a consequence of not getting this standard right.The recent findings by the space weather scientists about the intensity of the July 23, 2012 solar flare eruption should be a wake-up call for all. Professor Dan Baker, Director of the Laboratory for Atmospheric and Space Physics, University of Colorado - Boulder, recently said “I have come away from our recent studies more convinced than ever that Earth and its inhabitants were incredibly fortunate that the 2012 eruption happened when it did. If the eruption had occurred only one week earlier, Earth would have been in the line of |

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| | | fire."The risks and consequences of doing nothing, which is what would be mandated by this proposed GMD standard, is much higher than the risks and consequences of introducing proven and tested neutral blocking systems into the bulk electric power grid. Technical discussion and support of all of these points is included in following paragraphs.I. GMD Standard is Derived from Weak GMD DisturbancesThe proposed NERC GMD Standard is derived from recent data that is not representative of a large solar super storm. The storm data considered is from only the last several decades and does not even included the 1989 storm, one tenth the size of a solar super storm, which caused the damage and collapse of the Quebec power grid and also the catastrophic damage to the transformer in Salem, NJ. The potential consequences of a solar super storm are so dire that extreme care should be taken in developing a standard that has large acceptance in both the solar science community and the electrical power industry. Also a standard of this type should be based on many decades of recorded data which exists for example in Northern Europe (60 years of magnetic data) and Japan (89 years of magnetic data). This standard is one that we cannot afford to get wrong.II. New Hot Spot GMD Theory and Spatial Averaging ApproachThe proposed NERC GMD Standard has introduced a new so called Hot Spot theory which has never been published or vetted in a published paper. It assumes that there will be localized a hot spot of geomagnetic field in an area on the order of 100 by 100 kilometers. This theory cannot be supported for a solar super storm which is known to be thousands of times larger in extent when it hits the earth. There is no reasonable nor logical method to extrapolate data from recent magnetic data (the last several decades) for small storms to conclude that there will be localized hot spots for a solar super storm. Therefore the spatial averaging approach to reduce the GMD standard field from 20 V/km to 8 V/km is not a valid and accepted approach. Hence, the standard field should remain 20 V/km as published in a respected and referred journal two years ago by Pullkinen et. al. (2012).III. Reduction of Standard with Geo Latitude ScalingThe reduction of the GMD geo-electric field with geographic latitude cannot be justified with the use of data from weak solar storms as the GMD standard team has proposed. This proposed latitude scaling is a very steep function |

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| | | which may apply for the weak storms considered by the team but cannot be justified for a solar super storm. When the recorded history of the Carrington event shows that Northern lights were observed in Cuba, we cannot conclude that our southern states will not experience nearly the same geo-electric fields as or northern states and Canada. Again, much more care needs to be taken in the development of a latitude scaling function for this GMD standard. IV. Assumed GMD Waveform taken from a Weak Solar StormThe assumed GMD waveform used in the development of this proposed standard is taken from a weak solar storm and most likely does not represent the expected frequency content and sharpness of a solar super storm. It is known that weak solar storms that impact the earth travel at much slower velocities than do solar super storms. Therefore, the sharpness of the waveform of the magnetic disturbance will be greatly enhanced for a solar super storm. This sharpness or frequency content of the wave then relates to the generation of the geo-electric field since the field is directly related to the time derivative of the magnetic field. Hence, the proposed GMD field standard is certainly greatly understated as a result of this assumption in the development of the proposed standard.V. Assumption that Load Shedding and Brown Outs are an OptionThe GMD standard makes the assumption that to avoid power grid problems during a GMD event it will be acceptable to shed load and/or create brown outs to avoid grid voltage collapse and equipment damage. To our knowledge there are no other scenarios in the industry where load shedding is permitted. Additionally, since the space weather predictions/warnings from NOAA or other agencies are by no means 100% accurate, there could be a number of GMD events which simply do not couple effectively into the earth's fields, such that many times impacts to the grid are minimal and load shedding would not be warranted. Finally, it would be highly unlikely that a utility would endorse a load shedding policy in light of potential customer litigation in cases where a GMD event did not couple effectively into the grid. VI. Potential for Component Damage by GMD Produced HarmonicsThe proposed GMD standard does not adequately cover the potential for component damage to equipment, such as generators, SVCs and capacitor banks, by even moderate GIC currents that produce |

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| | | harmonics in half-cycle saturated transformers. While the potential for harmonic damage is briefly referred to, the proposed standard gives no guidance for harmonic levels that could cause damage. And the standard gives no guidance on how to analyze a network for this issue. VII. Probability of a Solar Super Storm Impacting the Earth AgainThe draft of this GMD standard quotes only one paper by J. F. Love which implies that the probability for a solar super storm is not very large (6.3% within the next 10 years). However, the standard drafting team should also quote several other papers on this topic which show the probabilities for a solar super storm as 12%, 13% and 14.7% within the next 10 years. These papers are by P. Riley (2012), R. Katakoa (2013) and R. Thorberg (2012). And these predictions extrapolate to a 50% probability within the next 50 years using the standard Poisson process. By all accounts this is a very high probability especially when the consequences of such a storm will be so paralyzing to our society and our way of life. It is know now recognized that solar super eruptions do not occur every 50 or 100 years from the sun but in fact erupt on average every 7.5 years. The difference is that many such super eruptions do not hit the Earth but instead travel outward in other directions. As an example the solar flare eruption of July 23, 2012 is now recognized as a solar super eruption. Professor Daniel Baker of the University of Colorado recently stated “In my view the July 2012 storm was in all respects at least as strong as the 1859 Carrington event, the only difference is it missed.”VIII. More Solar Weather Scientists Needed on the Standard Development TeamThe entire reduction of the geo-electric field standard from 20 V/km down to 8 V/km has been driven by only one solar weather scientist on the standard drafting team. Since this standard is so critical to our country, society and our existence, the drafting team should have included at least six if not more solar scientists on the team. The decision to limit the size of the drafting team for expedience or any other reason is a dangerous approach. And there exist many other noted and experienced solar scientists that would never agree with the methods used to develop this proposed standard. IX. Lack of a Safety Margin in the Proposed StandardIn most industries there are safety margins that are built into standards and requirements. Typically safety margins are on the order of 3 to 5 times |

| Organization | Yes or No | Question 2 Comment |
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| | | the largest load that might expected. In this case, since we are attempting to predict the geo-electric field of a solar super storm that has only occurred in 1859 and 1921 before modern measurement equipment, we should mandate that a safety margin be applied to the mean prediction of 20 V/km by Pullikenen et. al. (2012). So with a safety margin of say 3 times this mean prediction, the standard should be 60 V/km, not 8 V/km as proposed by the drafting team. X. Potential for Hidden Assumption that Mitigation will be ExpensiveIt appears likely that the team has may have concluded that mitigation achieved with equipment will be prohibitively expensive. The extreme opposite is in fact the case, the equipment, a neutral blocking system, is very inexpensive, uses off the shelf components and has been built, extensively tested and demonstrated in a live grid at Idaho National Laboratories. Independent studies by both the University of Manatoba and by EPRI show that the introduction of neutral blocking systems will not cause any unintended consequences for typical power grids. These studies have been made available to the industry within the last year. The equipment for one neutral blocking system is on the order of $300k with an installation cost of $50k or less. Studies performed by PowerWorld LLC for the state of Wisconsin and the state of Maine indicated that adequate protection of a states grid can be achieved with neutral blocking systems on about 50% of the HV and EHV transformers. The cost of this protection is estimated to be a $2 onetime charge per customer. Additionally, when a utility uses noneconomic dispatch whenever NOAA predicts a K7 or larger solar storm, the price of electric is increases since more expensive generation is purchased to avoid outages. But when neutral blocking systems are in place, this noneconomic dispatch procedure can be avoided. So it is estimated that under these conditions neutral blocking systems will provide a pay-back with 1 to 2 years. Hence, neutral blocking systems will reduce costs, provide a cost pay back within a few years and then reduce costs thereafter. |
| Ameren | No | (1) We believe that the Benchmark Geoelectric field amplitude of 8 V/km is overly conservative for a 1 in 100 year occurrence, and a safety margin of 25 percent as reported on page 14 of 27 of the Benchmark GMD Event is too much. (2) A GMD |

| Organization | Yes or No | Question 2 Comment |
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| | | event of 4-5 times the magnitude of the1989 Quebec event as the basis for the 1 in 100 year storm is perplexing, given the few “high magnitude” events that have occurred over the last 21 years. From our perspective, the requirements to provide mitigation for these extreme GMD events are not supported. |
| James Madison University | No | I have grave concerns about the methods used to calculation of geoelectric fields. See comments under question 7. |
| Minnkota Power Corporative | No | See NSRF Comments |
| Independent Electricity System Operator | No | The SDT has made a significant contribution by defining a GMD benchmark event but further steps in the process need more clarity.We do not agree the approach described in TPL-007 will allow planning decisions to be made with an acceptable level of confidence. We suggest the following process would provide an acceptable level of confidence: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.Comments from the SDT on this procedure would be received with great interest. |
| Oncor Electric LLC | No | The map in figure 1 on page 13 of the standard has BETA values that are very broad. We have a concern in reference to how and when we should use the BETA value. The standard suggests on page 12 “for large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for Î² should be used in scaling the geoelectric field.” We recommend that engineering analysis be used for |

| Organization | Yes or No | Question 2 Comment |
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| | | a more accurate distribution of the entities area since Oncor falls in between 2 different beta values of ip4 (0.41) and cp2 (0.95). We recommend the term “engineering analysis” be added to the standard itself similar to as in FAC-008 requirement 1.1. (Per the July NERC Technical Conference presentation, slide 104 suggests the use of engineering judgment. We would like to apply that here as well. |
| Tri-State Generation and Transmission Association, Inc. | No | The 8 V/km benchmark event is at the upper end of the range of probable 100 year events. This will help assure that the industry is prepared for GMDs however, it may prove to be financially wasteful to the majority of the industry. Instead the industry should prepare for the median value from a 100 year event. Further, the NERC GMD team has provided Earth Resistivity Region maps that would be helpful to determine the Î² scaling factor to apply the benchmark event to our region, but those USGS derived maps do not include the majority of our service territory. The areas missing are the Northern, Middle and Southern Rocky Mtns and the Wyoming Basin. Tri-State’s service territory of 200,000 square miles is right in the middle of these four undefined areas. Tri-State would appreciate guidance from NERC on how these area’s will be handled in the future. |
| ACES Standards Collaborators | Yes | Although we agree with the guidance provided in Attachment 1, we still feel the SDT should develop an exception process mechanism for entities that are geographically located in the lower latitudes or certain Physiographic Regions to follow. For such entities, conducting such a study, for locations that are less susceptible to GMD events or less likely to produce large geoelectric fields, is an unnecessary burden on their resources. |
| Arizona Public Service Company | Yes | |
| Dominion | Yes | |

| Organization | Yes or No | Question 2 Comment |
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| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| SERC Planning Standards Subcommittee | Yes | |
| Bureau of Reclamation | Yes | |
| Duke Energy | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |
| Bonneville Power Administration | Yes | |
| Massachusetts Attorney General | Yes | |

| Organization | Yes or No | Question 2 Comment |
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| Exelon | Yes | While the proposed Benchmark event appears to be technically justified and provides the necessary basis for conducting assessments, the level of detail suggested for conducting transformer thermal assessments seems overly complicated and cumbersome. Recommend that a streamlined methodology be developed, or defined by the PC or TP, to evaluate transformer thermal impacts based on high-level characteristics of the Benchmark event and the analysis performed by the PC or TP. Any real event will likely share general characteristics with the Benchmark event, but will be completely different in terms of its actual signature. A more straightforward evaluation methodology would be more efficient and possibly just as effective as detailed analysis for each transformer based on a specific signature. The Thermal Assessment whitepaper describes a technique that consists of selecting a GIC pulse representative of the GIC peak. Could one (or more) pulses be defined with a magnitude and duration that are representative of the “worst” part of the Benchmark event and used as a standard test for R6? It seems this would not be much different than the simplified analysis described in the whitepaper, except that a uniform test would be defined rather than allowing each entity to choose what they believe a representative GIC pulses may be. Additionally choosing a worst case could allow for creating specifications for new transformers to assure that they can withstand the event and allow for establishing a uniform test pulse so manufacturers could more effectively perform testing and provide data which will ultimately be requested from all of their customers once the standard goen into effect. |
| ladwp | Yes | |
| Hydro One | Yes | The benchmark event is reasonable and consistent with engineering practices. It accounts for regional differences and provides a floor from which applicable entities can expand if needed. |

| Organization | Yes or No | Question 2 Comment |
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| American Transmission Company, LLC | Yes | |
| CenterPoint Energy | Yes | CenterPoint Energy commends the SDT's work on this issue. CenterPoint Energy believes the SDT work product is a significant improvement over earlier efforts resulting from the collaboration of NASA, the country's expert space agency, and electrical modeling experts from industry. Applied holistically, the design basis event would involve the convergence of a 100 year GMD event under conservative time domain characteristics coincident with worst case field orientation coincident with stressed system conditions, all of which would simultaneously occur with a frequency on the order of once every several millennia. Even so, CenterPoint Energy believes the conservative approach resulting from the collaboration of the experts on the SDT is appropriate and reasonable. |
| Idaho Power | Yes | |
| Xcel Energy | Yes | |
| Northeast Utilities | Yes | |
| LCRA Transmission Services Corporation | Yes | |
| American Electric Power | Yes | |
| Hydro One | Yes | The benchmark event is reasonable and consistent with engineering practices. It accounts for regional differences and provides a floor from which applicable entities can expand if needed. The determination of geomagnetic latitude table in Attachment 1 should probably be interpreted as an approximate guide to determine the geomagnetic latitude of a given network. More accurate determination of |

| Organization | Yes or No | Question 2 Comment |
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| | | geomagnetic latitude can easily be determined with a number of publicly available tools. The geomagnetic field factor alpha in Table I in the Appendix should also be viewed as an approximation of alpha factors more readily calculated with equation xx in the Appendix. The geomagnetic field factor alpha accounts for regional differences and provides a floor from which applicable entities can expand if needed. This scaling factor can also be used to approximate non-unniform geoelectric fields in a geographically large service territory in steady-state calculations.The selection of 8 V/km is a reasonable compromise for a 100 year return event, as suggested by the FERC order. It is difficult to characterize a wide area system event by a single peak in a geographically confined local geoelectric/geomagnetic field enhancement. Although the value is primarily based on magnetic field measurements in Europe because such measurements are sparse in North America, it is consistent with the historical values measured in from North America. With additional measurements over time, a better value may be obtained. The 8 V/km is the best possible estimate at this time with the available data. The extreme value analysis provided in the GMD benchmark white paper provides mathematical rigor. From an engineering point of view it makes more sense to for spatially-averaged values to be used to assess wide-area impact, as opposed to 20 V/km estimate when only storm peaks were considered in the 2012 NERC GMD interim report. |
| Public Service Enterprise Group | Yes | |
| Ingleside Cogeneration, LP | Yes | ICLP believes that the best knowledge available to the industry has been used to develop GMD benchmarks and planning criteria. We expect corrections will be made as actual event data is accumulated and compared to simulation results. |
| Entergy Services, Inc. | Yes | |
| Pepco Holdings Inc | Yes | |

| Organization | Yes or No | Question 2 Comment |
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| Texas Reliability Entity | Yes | |
| Georgia Transmission Corporation | Yes | |
| DTE Electric | | No Comment |
| Public Utiltiy District No. 1 of Cowlitz County, WA | | Cowlitz defers to the Planning Coordinators and Transmission Planners. |

3. **Transformer Thermal Impact Assessment. The SDT revised the requirement for conducting transformer thermal impact assessments. In the revised draft TPL-007-1, only those applicable transformers have calculated GIC flow of 15 Amperes or greater per phase of effective geomagnetically-induced current (GIC) are required to conduct a transformer thermal impact assessment. A review of available transformer thermal models supports this as a conservative screening criteria. Do you agree with the proposed 15 Amperes threshold? If you do not agree or have recommended changes to the transformer thermal impact assessment requirement please provide your suggestion and technical justification, if applicable.**

**Summary Consideration: The drafting team thanks all who commented on the transformer thermal impact assessment. All comments have been reviewed and the revised version of TPL-007-1 and supporting white papers include changes.**

**A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections:**

- **Screening criteria. Commenters stated that 15A threshold was overly conservative, particularly for some types of transformers. Commenters proposed that a percent-loading threshold be included so that light-loaded transformers were excluded from thermal assessment, or that a higher GIC screening threshold be established for transformers that are operated below nominal power. A commenter recommended that a thermal impact assessment not be required for any transformer with a GIC design specification in excess of the calculated GIC in Requirement R5. A commenter noted that the transformer thermal screening criterion whitepaper cited only equipment rated 400 MVA or less and asked if the criterion was also valid for larger equipment.** The SDT agrees that the threshold for 3-phase 3-limb transformers is expected to be higher than the threshold for single phase units. However there is insufficient thermal measurement data of 3-phase 3-limb transformers to develop a technical justification at this time. The SDT also agrees that a design specification is a valid criteria for determining whether a transformer thermal impact assessment is required and has added this criteria to the application guidelines section. The drafting team agrees that loading and ambient temperatures have a direct bearing on hot spot thermal limits. However, different transformer types have different temperature/loading performance and cooling modes. From a planning perspective it is not possible to anticipate planned or unplanned outages and system configuration. Therefore, a general threshold on the basis of loading temperatures is not prudent. This does not prevent using a technically supportable loading-based assessment on a case-by-case basis as indicated in the white paper. Also it is generally not possible to anticipate a % loading that would apply to the exact system configuration in view of planned and unplanned outages and contingencies. The temperature rise due to hot spot heating thresholds due to half-cycle saturation do not depend on the transformer MVA rating.
- **Technical basis for thermal assessments. A commenter disagreed with the white paper because the thermal heating models used as examples were not compared against experimental data. A commenter did not agree that thermal time constants were on the order of minutes to tens of minutes as described in the white paper.** The white paper now includes an example of

a comparison with measured results. Winding and metallic hot spot time constants to a GIC step mentioned in the white paper are based on published measurements and manufacturer-calculated and measured hot spot temperature rises (e.g., Fingrid transformer) and are not consistent with temperature time constants of 20 to 60 s.

- **Temperature limits. A commenter believes using IEEE Std. C57.91 emergency loading limit of 120 C is overly conservative and suggested 130 C or 140 C. The commenter also stated that the thermal impact assessment white paper did not take transformer defects into account.** According to Std. IEEE 57.91, a hot metallic part hot spot during the emergency overloading time frame will not cause gassing in a healthy unit. The SDT believes this is the most appropriate criteria currently available. To account for the condition of a particular transformer, an owner can de-rate a transformer thermal limit. This is discussed in the white paper.
- **Transformer thermal impact assessment approach. A commenter did not agree with the overall approach stating it did not consider several non-linear phenomena relevant to transformer heating due to GIC. A commenter asked for clarification on the duration of the GIC time-series, while another commenter proposed an alternate approach based on a fixed-time pulse of GIC determined based on transformer rating.** The sample method to calculate the thermal response is peer-reviewed and the white paper shows that it reproduces the Fingrid measurements. The white paper has been modified to include these results. This method uses a linearized approximation of the asymptotic response to different GIC steps. All nonlinear effects are taken into consideration. This is simply a method to model a known transformer thermal step response in order to calculate incremental hot spot temperatures as a function of time caused by an arbitrary GIC(t). The transformer thermal step response needs to be known or assumed from measurements or calculations. When the step responses are known only for low values of GIC, the linear extrapolation of asymptotic response is known to be conservative, on the basis of measurement data. However, in the absence of information on a specific transformer, it is a simple way to obtain conservative values. The standard does not place any restrictions on the transformer thermal response used in the assessment, so long as it is technically justifiable. For instance, technical justification would be a manufacturer warranting a specific or general thermal response.
- **Scope of transformer assessments. A commenter stated that the standard should also include assessments for shock or vibration impacts.** Vibration is not considered in the standard because available information is sparse, mostly anecdotal and not likely to have a wide area impact on the network.
- **A commenter disagreed with the requirement in R2 part 2.1 to study off-peak conditions.** Minimum loading should be examined because the generation pattern and thus the distribution and availability of reactive power resources are completely different than on-peak conditions.
- **Effective GIC. A commenter did not agree with the calculation for effective GIC.** The equivalent GIC formula in an autotransformer is based on ampere-turns, not resistance. Ampere-turns determine the degree to which the core is saturated, which in turn, determines the eddy currents and harmonics that cause hot spot heating. The GIC proportion in HV and LV windings depends on factors such as circuits connected to the transformer buses (length and resistance), station grounding

resistance and number of transformers connected to the bus. The impact of winding resistance on the level of saturation of the transformer has only a minor effect on GIC distribution in the windings. The effective current used to calculate GIC(t) is a simple and direct result of the dc simulation of the network.

- **Cost and availability of manufacturer GIC capability curves or models. Commenters are concerned that models will not be available from manufacturers and that default models are unavailable. A commenter recommended that the standard include allowances for application of 'sound engineering judgment'.** The SDT agrees that industry-vetted default thermal models would be beneficial to the industry. It is in the scope of work for the NERC GMDTF is evaluate available models and provide guidance. This would be a better forum for discussion and vetting. In response to stakeholder concerns, the revised implementation plan provides four years before the thermal assessment requirement become effective.
- **Tertiary windings. A commenter indicated that tertiary winding heating is a major problem because tertiary windings have a lower MVA rating than main windings (some below 5%).** Heating due to harmonics and stray flux in the tertiary winding does take place. The thermal impact assessment is intended to examine metallic part and winding hot spot heating. The requirement is not specific to a particular winding.
- **Entity obligations for R6 part 6.3 Suggested Actions. A commenter stated that it was unclear how suggested mitigation actions are implemented.** Part 6.3 specifies that the owner must communicate actions to mitigate the impact of GICs on the applicable power transformer and provide supporting analysis to the planning entity conducting the GMD Vulnerability Assessment. This provides the necessary feedback for the planner to account for potential impact in the assessment. The SDT believes this is an effective approach consistent with planning standards.
- **Thermal assessment tools. Commenters stated that software tools were needed for thermal assessment. A commenter supported the approach but highlighted the importance of transformer design-specific models.** The SDT agrees that the precise thermal response is design-dependent and anticipates that this standard will influence transformer manufacturers to produce families of technically-justified conservative default for the industry to use. Special software is only one of methods that can be used to carry out a thermal assessment. For example, an entity can use manufacturer-supplied capability curves. Specifications for new transformers can require OEM to perform the thermal assessment and provide the necessary GIC rating curves to the customer. The NERC website provides one software implementation of a peer-reviewed method to estimate hot spot temperature rise when a transformer thermal step response to GIC is known. This implementation can be used to carry out thermal assessments. http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Planning-Tools.aspx

| Organization | Yes or No | Question 3 Comment |
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| PacifiCorp | No | R 2.1 requires the study of peak and off-peak conditions. It is reasonable to study peak load conditions. However, the requirement to study off-peak conditions that may obviously be non-critical in some systems could be a waste of engineering resources that are in short supply due to the increase in study requirements in so many of the new standards and revisions. Also, there should be a % loading threshold so that effort is not wasted in a thermal study of a lightly loaded transformer that sees a relatively small GIC flow as low as 15 A. |
| Northeast Power Coordinating Council | No | Regarding Requirements R5 and R6 - The 15 Ampere (A) threshold is overly conservative if applied to all types of transformers. While 15A may be a reasonable number for some types of single-phase and shell-form transformers, the majority of core-type transformers may tolerate much higher GICs. It is recommended that different thresholds be established for various types of transformers. For technical justification, see Fig. 12 of the “Transformer Thermal Impact Assessment” white paper draft, based on which GIC below 50 Amps per phase has no impact on the transformer under study. Also see “ Methodology for Evaluating the Impact of GIC and GIC Capability of Power Transformer Designs” by Ramsis Girgis and Kiran Vedante presented at the IEEE Power and Energy Society General Meeting in 2013, which shows no significant impact under 150 A/phase. Other studies are available in support of the selective approach of thresholds. Recommend the adoption of a 50 Ampere across the board threshold. However, should the drafting team be unable to adopt this revised across the board threshold, then we recommend the two tier thresholds that follow: Transformer Types Threshold (Amperes)Single phase and shell-type 15A3-phase core-type and other 50AA different threshold can be determined after entities have more experience.The white paper on the justification for the 15 A threshold is based on published measurements. This is a prudent and conservative approach. Manufacturer-calculated values can vary widely depending on the manufacturer, and at this point in time, few have been validated by measurements. The degree of half-cycle saturation in single-phase units compared to core-type three-phase three-winding units is a matter that will require more study |

| Organization | Yes or No | Question 3 Comment |
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| | | and clarity in the future. The susceptibility of these units to GIC depends strongly on the zero sequence magnetizing impedance of the transformer. The zero sequence magnetizing impedance has an important impact on the level of GIC at which a three-phase three-winding core type transformer will saturate. This parameter is not routinely measured in the factory, but it would be useful for entities to request this information from transformer manufacturers. |
| Foundation for Resilient Societies | No | Comments on “Transformer Thermal Impact Assessment White Paper”1. The premise of this white paper is that thermal heating is the only failure modality for transformers subjected to GIC. There have been many reports of vibration effects on transformers and vibration could be causing failures even without heating. The effects of shock or vibration do not require long time constants; near immediate damage might occur after a “GIC shock.” It is an unwarranted assumption that NERC modeling needs to only account for thermal effects.2. The thermal heating models presented in the white paper are not compared against experimental data. Therefore, the thermal models might be wrong. We cannot have the lives of millions of people dependent on unvalidated thermal models.Comments on “Screening Criterion for Transformer Thermal Impact Assessment”Quoting from the document:Half-cycle saturation results in a number of known effects: o Hot spot heating of transformer windings due to stray flux; o Hot spot heating of non-current carrying transformer metallic members due to stray flux; o Harmonics; o Increase in reactive power absorption; and o Increase in vibration and noise level.This paper focuses on hot spot heating of transformer windings and non current-carrying metallic parts.Effects such as the generation of harmonics, increase in reactive power absorption, vibration and noiseare not within the scope of this document.1. We could not find anywhere in the draft standard where the effects of vibration on transformers are addressed.2. No validation of the thermal models or manufacturer capability curves is presented in the whitepaper, except for Figure 4 that appears to show results for a single test. The FDA would not accept safety tests of a drug in a single patient, nor should NERC and its Standard Drafting Team rely on a single |

| Organization | Yes or No | Question 3 Comment |
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| | | transformer test when millions of lives are at stake.3. If NERC, electric utilities, and transformer manufacturers are confident in the hypothesis that damage to transformers will require minutes of GIC exposure, we suggest that they subject representative EHV transformers to 60 seconds of 1,000-2,000 amp DC injection and record the thermal and vibration results. |
| PPL NERC Registered Affiliates | No | Introducing a minimum GIC figure for thermal assessment is an improvement, but it is recognized in the industry that single-phase transformers, such as are generally used on 500 kV-and-up generator step-up transformers (GSUs), are much more susceptible to geomagnetic disturbances (GMDs) than are the three-phase GSUs used at lower voltages. It therefore appears that separate min-GIC values should be specified for single-phase and three-phase equipment. |
| DTE Electric | No | If special software is required by the transformer owner to perform the thermal assessment using the supplied GIC waveform, then examples of software should be provided in the white paper. It would be beneficial to have more detail concerning the thermal assessment and transformer thermal response model analysis. |
| Manitoba Hydro | No | The transformer thermal assessment proposal is very new and has not been thoroughly examined by the industry or by transformer manufacturers. The GMD TF admits that manufacturers are just beginning to create hot spot heating models. Existing transformers may not have been assessed for GIC and manufacturers may not be able to calculate withstand on old designs. Perhaps the impact assessment should be limited to more critical transformers that have at least one winding greater than 300 kV. The GMD assessment could be used to assist the Transmission Owner in developing specifications for new or replacement banks. Rather than only a default level of 15 Amps, a larger exemption should also be allowed if the transformer was specified and confirmed by the manufacturer to withstand larger values. R6 should be limited to critical transformers (greater than 300 kV) that have a manufacturer GIC capability curve, where the assessment shows very high GIC levels (at or above the |

| Organization | Yes or No | Question 3 Comment |
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| | | manufacturer confirmed withstand levels). Referring to the “Transformer Thermal Impact Assessment White Paper”: o Page 3, 1st bullet: Using the standard hotspot limit for the winding (120'C) will be too conservative and limit the capability of the transformer. Since GIC is so transient in nature and the really high values occur very seldom, more risk should be allowed. Please consider 130 or even 140'C hotspot temperature as a limit. o Page 3, last bullet: The equation for effective GIC is fundamentally wrong for the following reasons:o GIC does not divide within a transformer by the ratio of voltages nor is it determined by Amp-Turns. It is either essentially steady-state dc and divides by dc resistance, or it is a transient that charges the core and does not have amp-turn balance amongst the windings. o The GIC division between windings in an auto-transformer is primarily determined by the relative dc resistances of the grounding circuit (common plus ground circuit) and the LV line resistance including the system.o The formula given assumes ac or transients that are induced into the other circuit, which is not what we are trying to model.o Why would one want to know a single equivalent current? It doesn't make sense unless you also define an equivalent single dc resistance. And it would require more than one equivalent current, because this would change depending upon which way the current is flowing (HV to LV or LV to HV).o The white paper states that we have to use the generic formula. What about instances where the exact current relationship is identified through tests?o If the Standard is going to require us to calculate the temperatures within the transformer, then we should at least determine the correct current passing through the circuits of the transformer. o Page 4, point 1: It will cost utilities significant dollars (and lots of time) to obtain these capability curves for existing transformers. o Contrary to what is stated, every manufacturer will produce the GIC capability curve based on steady-state dc current because no GIC standard exists. No wave shape or timing will be assumed. Why would the manufacturer risk making assumptions related to wave shape or timing? o There is no difference to the hotspot temperature for durations of 10 and 30 minutes. So why would a manufacturer differentiate between these? o The example curve (Figure 2) is quite useless. What is the rated ac current of this transformer that withstands thousands of |

| Organization | Yes or No | Question 3 Comment |
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| | | dc amps? If this curve is for a 10 to 15 kA transformer that is a poor example to give. o Page 5, Figure 3: Heating to these temperatures (~200'C) contradicts Page 3, first point. Heating to these temperatures will result in free gas bubble formation, which puts the transformer at extreme risk of dielectric failure. o Page 5, point 2: o The statement, "Transformer hotspot heating is not instantaneous," is not really true for the clamping structure. Certain parts can heat up in as little as 10 to 15 seconds depending upon amount of flux; 20 to 60 seconds is typical. It happens very fast. (Manitoba Hydro has test data indicating this for step-up transformer tie-plates). o The statement, "The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes...," is also not true. Winding time constants are typically 2 to 6 minutes. The metallic parts are much shorter.FROM CG Power Systems Canada Inc (Transformer Manufacturer)The NERC proposal to use a transfer function approach to estimate the heating effects of GIC on ANY transformer is fundamentally wrong. The transfer function can only be used to analyze the response of linear systems, or systems which can be lineralized in certain ranges of interest. The non-linear phenomena not considered include:1. Conversion of unidirectional time-varying GIC into a corresponding steady state DC current,2. Transformation of the GIC excitation currents to the corresponding half-cycle pulses,3. Transformation of the half-cycle pulse into a Fourier series of harmonic currents,4. Transforming the fundamental frequency (load) current and GIC derived harmonic currents into heating of the non-linear materials of the core and clamping system.Due to these inaccuracies the thermal response tool (transfer function) can only be used under the following conditions:1. The thermal response tool is adjusted to the specific transformer being analyzed (by comparing design to test results or by directly testing the transformer and adjusting the parameters of the transfer function),2. The thermal response tool is only used in the range of the tested dc currents (the extrapolation of the response beyond the tested dc currents will likely result in highly exaggerated results),3. The thermal response tool is not used on unknown designs (as it will most certainly result in the wrong values for the temperature rise of metallic parts).It may be a good idea if some treatment is |

| Organization | Yes or No | Question 3 Comment |
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| | | included in the transformer white paper on how to include GIC withstand capability in the specifications of transformers when the power utilities go out for tender. In some instances, there is no specific requirement and a customer just wants to know what is the transformer withstand for GIC, that is not an issue. Others will include a specific curve and say the transformer must withstand it. However often times this curve is not indicative of what the transformer will actually see. Frequently seen is the exact copy of a profile put forth in Ramsis Girgis' paper "Effects of GIC on Power Transformers and Power Systems" which is itself roughly 5 times greater than the 1989 GIC event.Every transformer has a defect. Some of those defects will affect GIC capability. Yet there is no discussion in this paper about common defects that would limit capability.Manitoba Hydro has no objection to doing assessments according to the white paper but be consistent in the accuracy desired at each step. Don't make step 1 totally inaccurate and then try to make step 2 highly accurate.Can NERC tell us how many transformers failed (or are suspected to have failed) due to GIC over the last 10 years? |
| Hydro-Quebec TransEnergie | No | The 15 A criterion should not be applicable for three-phase, three limb power transformers as it has been demonstrated by the industry that these transformers are far less sensitive to DC currents than single-phase and three-phase five limb power transformers as those tested and used to define the criterion. We recommend that another criterion (higher DC current) should be considered for three-phase three limb power transformers. We also recommend considering to relax the 15 A criterion for specific transformers for which it would be demonstrated with measurements and statistics that they are operated significantly below their nominal power. The effect of ambient temperature should also be considered as it significantly reduces the heating of power transformers. |
| Emprimus | No | The GMD standard does not adequately consider transformers with tertiary windings which makes these transformers more vulnerable to GIC currents and subsequent heating. |

| Organization | Yes or No | Question 3 Comment |
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| Ameren | No | The Screening Criterion for Transformer Thermal Impact Assessment document cites several instances where transformers all rated 400 MVA or less are exposed to GIC currents to determine their thermal response. However, the predominant rating for transmission transformers on our system is 560 MVA or larger. We ask if these transformers in general are to be expected to withstand greater than 15 A before reaching a 50 degree C temperature rise? |
| Associated Electric Cooperative, Inc. - JRO00088 | Yes | |
| ACES Standards Collaborators | Yes | |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | Yes | |
| Arizona Public Service Company | Yes | |
| Dominion | Yes | |
| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| Colorado Springs Utilities | Yes | No Comment |
| Bureau of Reclamation | Yes | |
| Duke Energy | Yes | |

| Organization | Yes or No | Question 3 Comment |
|---|---|---|
| MRO NERC Standards Review Forum | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | |
| SPP Standards Review Group | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |
| Bonneville Power Administration | Yes | |
| Massachusetts Attorney General | Yes | |
| Exelon | Yes | |
| Volkmann Consulting, Inc | Yes | |
| ladwp | Yes | |

| Organization | Yes or No | Question 3 Comment |
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| Hydro One | Yes | It is difficult to come up with a different threshold until entities have more experience. |
| American Transmission Company, LLC | Yes | |
| CenterPoint Energy | Yes | CenterPoint Energy appreciates the diligent efforts of the SDT and CenterPoint Energy is voting to approve TPL-007-1 as a reasonable set of requirements for GMD planning based upon the current state of the art in this evolving area of study. The 15 ampere threshold is less than the threshold level recommended by CenterPoint Energy in earlier comments, but CenterPoint Energy is willing to support that extremely conservative threshold if it is agreeable to the majority of industry stakeholders. Besides CenterPoint Energy, multiple other industry stakeholders expressed concerns about the transformer thermal impact requirements of the initial draft standard during the informal comment period. If the June, 2014 version of the draft standard is not approved by industry stakeholders, and if multiple parties continue to express concerns about the transformer thermal impact requirements of the standard, CenterPoint Energy offers the following thoughts and suggestions for modifying the standard for the second ballot. Read holistically, Requirements R6.1 and R5.2 require that G(t) be calculated based on benchmark GMD event waveform and, furthermore, that owners use that calculated waveform to perform a transformer thermal assessment. CenterPoint Energy understands and agrees that the prescribed approach is technically justified and can be implemented with training, proper tools, and reasonably accurate transformer data. However, there are no commercially available tools at this time. Even if one entity provides its tool for industry use, the situation is less than ideal because users cannot choose among two or more tools from multiple vendors and the tool will not have been vetted and improved based on feedback from multiple users, as is commonly done through beta testing of modeling software. Even if adequate tools are available, accurate data for most transformers is not available. Accordingly, CenterPoint Energy has come to |

| Organization | Yes or No | Question 3 Comment |
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| | | believe that whereas the prescribed approach is technically valid and may be feasible to implement, it is at best an approximation limited by data quality and other uncertainties. CenterPoint Energy believes there are valid alternative ways to approximate the thermal impact of the benchmark GMD without calculating G(t). The benchmark waveforms selected by the SDT using a 1989 historical event are reasonable and conservative based on the information available to the SDT, but almost certainly those waveforms will not occur in a future GMD event. The Transformer Thermal Assessment Whitepaper discusses using average GIC values over a two minute or five minute time interval as a valid assessment approach. One limitation of this approach is that using a single two or five minute interval from a 30 hour G(t) waveform fails to account for transformer heating and cooling that occurs from previous GIC peaks. CenterPoint Energy believes that heating effects from previous GIC peaks can be reasonably assessed by applying the peak GIC value, instead of the average GIC value, over a two or five minute interval. To err on the conservative side, a five minute interval can be applied. Another layer of conservatism can be applied by assuming that a transformer is loaded to 100% of its normal (continuous) rating coincident with the two or five minute interval that the peak GIC value is applied. For network elements, such as autotransformers, it is highly unlikely that the transformer would be loaded to 100% of its continuous rating due to the redundancy requirements of planning and operating standards (i.e., the system must be planned and operated to be at least n-1 secure). The approach described in the preceding paragraph would not require G(t) to be calculated. The owner would apply the peak GIC from Requirement R5.1 for five minutes to a transformer loaded to 100% of its normal rating, and compare this to an estimated (in most cases, generic) transformer heating model. CenterPoint Energy believes that the standard could be modified to allow such an approach by eliminating Requirement R5.2, which would reduce the burden upon planning entities while still enabling transformer thermal assessments to be performed. CenterPoint Energy believes the burden upon owners can be reduced by modifying Requirement R6 such that a transformer thermal assessment must be performed for the greater of 15 |

| Organization | Yes or No | Question 3 Comment |
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| | | Amperes per phase or some percentage, such as 10%, of a transformer's normal rating. For example, a transformer with a normal rating of 500 Amperes per phase would only be assessed if the peak GIC is 50 Amperes per phase. CenterPoint Energy believes that if the peak GIC value is less than 10% of a transformer's rating, that transformer is not materially at risk of overheating, and at even less risk of failure, due to various reasons. Among other things, the transformer, especially an autotransformer, is likely loaded at significantly less than 100% of its normal rating throughout the GMD event and particularly so at a specific, limited moment when the peak magnitude of a geoelectric field coincides with the worst case field orientation from a rare (100 year) GMD event. Even if this highly unlikely set of circumstances converged for a single transformer, it is even less likely that this improbable set of circumstances would converge for two or more transformers, and the possible loss of one transformer is already addressed by planning and operating requirements. Accordingly, if changes in the transformer thermal assessment requirements are necessary based on the results and comments from the initial ballot, CenterPoint Energy asks the SDT to consider changes that would allow alternative, less onerous approaches of assessing transformer thermal impacts such as the approach described in these comments. |
| Idaho Power | Yes | |
| Xcel Energy | Yes | |
| Nebraska Public Power District | Yes | |
| Northeast Utilities | Yes | |
| LCRA Transmission Services Corporation | Yes | |

| Organization | Yes or No | Question 3 Comment |
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| American Electric Power | Yes | AEP has had discussions with at least one transformer manufacturer on obtaining the required GIC thermal response data for existing units in order to conduct thermal assessments. One manufacturer owns the data for a large majority of our current fleet, and indications are that it may not be possible for them to obtain the required information. If such is the case, AEP may be required to utilize generic models for a large percentage of its transformer fleet. As a consequence, the generic thermal models will assume a significant role in the analyses and subsequent results. Due to the anticipated criticality of the generic models 1) the proposed standard cannot be properly reviewed, and its impact fully determined, until the models are provided, and 2) the models must be provided while the project is still active, so that industry has the opportunity to provide comments. Otherwise, industry risks being presented with generic models they don't agree with without a forum to debate them.During the technical conference, the drafting team inferred that "sound engineering judgment" would be allowed in assessing thermal vulnerability. AEP agrees with this approach; however the current draft provides no such allowance. The standard would have to clearly indicate what is and is-not "sound engineering judgment" so compliance can be clearly shown and proven. AEP requests that the drafting team incorporate this concept that they apparently believe is already is allowed by the proposed standard.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. 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. |
| Hydro One | Yes | The white paper on the justification for the 15 A threshold is based on published measurements. This is a prudent and conservative approach. Manufacturer- |

| Organization | Yes or No | Question 3 Comment |
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| | | calculated values can vary widely depending on the manufacturer, and at this point in time, few have been validated by measurements. The degree of half-cycle saturation in single-phase units compared to core-type three-limb three-phase units is a matter that will require more study and clarity in the future. The susceptibility of these units to GIC depends strongly on the zero sequence magnetizing impedance of the transformer. The zero sequence magnetizing impedance has an important impact on the level of GIC at which a three-phase three-limb core type transformer will saturate. This parameter is not routinely measured in the factory, but it would be useful for entities to request this information from transformer manufacturers. |
| Public Service Enterprise Group | Yes | |
| Ingleside Cogeneration, LP | Yes | Again, ICLP believes that the best knowledge available to the industry has been used to develop the criteria for thermally-susceptible transformers. As a result, we cannot offer a better GIC current threshold at this time.However, we would like to see NERC commit to a process where the set of identified components is evaluated for consistency. It is of clear interest if one planning entity returns results significantly different than one located in a comparable region. Reliability is best served if ALL at-risk transformers are identified, while those not-at-risk are not. ICLP suspects it will take several iterations of comparative studies before that level of precision can be reached. |
| Entergy Services, Inc. | Yes | |
| Pepco Holdings Inc | Yes | |
| Texas Reliability Entity | Yes | |
| James Madison University | Yes | |

| Organization | Yes or No | Question 3 Comment |
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| Minnkota Power Corporative | Yes | |
| Independent Electricity System Operator | Yes | We agree the proposed 15A threshold is a conservative screening threshold. Some transformers in Ontario experienced higher GIC levels than 15A/phase during the 1989 event with no material long-time adverse effects. |
| Oncor Electric LLC | Yes | |
| Georgia Transmission Corporation | Yes | |
| Tri-State Generation and Transmission Association, Inc. | Yes | Tri-State agree with the 15 A/phase GIC threshold for now based on existing analysis, but urge the NERC GMD Advisory group to finalize and issue the “Transformer Modeling and Testing” project and report. Tri-State believes that if this report is based on additional empirical data then it may verify a higher GIC threshold. Also, this report may help significantly with the analysis needed to estimate the GIC caused thermal changes and harmonics levels. The IEEE standard C57.91 recommended by NERC covers only the estimation of loss-of-life for various overload and high temperatures, but does not provide guidance on calculating the effect of GICs. |
| Public Utiltiy District No. 1 of Cowlitz County, WA | Yes | Cowlitz does not have the expertise to offer substantive opinion. However, we agree with a conservative approach until a greater knowledge base is developed. |
| MidAmerican Energy | Yes | |
| SERC Planning Standards Subcommittee | | no comment |
| Siemens AG Austria - Transformers Weiz | | Here is my comment about transformer models to calculate the thermal transformer response during GIC:A thermal response tool is a very suitable method to evaluate |

| Organization | Yes or No | Question 3 Comment |
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| | | the thermal risk of a transformer during a solar storm. But it is essential, that the simulations are based on calculation models what consider the specific transformer design. These models consider design elements like tie bars, clamping plates or tank shielding. Also the thermal influence parameters (cooling surface, thermo-hydraulic behavior) must be considered. Such calculation models can be also verified by special GIC tests. Of course, if a test in a laboratory is done, then the influence of the laboratory setup must be considered in the simulation. Such tests are described in the paper "GIC strength verification of power transformers in a high voltage laboratory" 1). 1) J. Raith, “GIC strength verification of power transformers in a high voltage laboratory”, (GIC workshop, Cape Town, 2014) |
| Luminant Generation Company LLC | | We do not have enough information to effectively evaluate this methodology. |
| Luminant Energy Company, LLC | | We do not have enough information to effectively evaluate this methodology. |

4. **Implementation. The SDT revised the proposed Implementation Plan based on stakeholder comments. The changes provide additional time for completing transformer thermal impact assessments. An overall timeline of four-years from the standard's effective date until completion of all steps in the GMD Vulnerability Assessment process including development of a Corrective Action Plan, if required, has been maintained. Do you support the approach taken by the SDT in the proposed Implementation Plan? If you do not agree with the proposed Implementation Plan, please provide your recommended changes and justification.**

**Summary Consideration:** The drafting team thanks all who commented on the Implementation Plan. All comments have been reviewed and the revised Implementation Plan is extended from 48 months to 60 months with the following specific changes:

- **Requirement R1. Some commenters indicated that 60 days was not enough time to meet with the Transmission entities and agree on an assigned set of responsibilities.** The SDT agrees with the comments and has changed proposed effective date to 6 months (from 60 days).
- **Requirement R2. Some commenters indicated that not enough time was provided to develop the models necessary to undertake the required analyses.** In the revised implementation plan, 18 months are allotted from the effective date of the standard until R2 is enforceable. The SDT believes this proposed timeline is achievable.
- **Requirement R5. Some commenters indicated that 18 months was not enough time to model GIC flows.** The SDT agrees with the comments and has changed the proposed effective date to 24 months (from 18 months).
- **Requirement R6. Some commenters indicated that 36 months was not enough time to perform the thermal assessments, given the need to acquire capability information from the transformer manufacturers and the need to perform this task for what is, at this time, an unknown number of transformers.** The SDT agrees with the comments and has changed the proposed effective date to 48 months (from 36 months).
- **Requirements R3, R4, and R7. Comments received indicated that 48 months was not enough time to perform the GMD vulnerability assessment and develop a Corrective Action Plan, given that the process will be new to the planners, require data that is not currently available to planners, and dependent upon pre-requisite steps that would be performed by others.** The SDT agrees with the comments and has changed the proposed effective date to 60 months (from 48 months).
- **Shorten implementation. Some commenters recommended reducing the timeline. A commenter stated that the timeline should include implementation of corrective action.** The SDT believes the revised implementation plan is appropriate for the planning approach taken in TPL-007.
- **Florida entities stated a variance or delay was needed due to availability of a Florida earth models.** Researchers at U.S. Geological Survey have developed a model for Florida which should enable entities to conduct GMD Vulnerability Assessments within the proposed Implementation Plan.

| Organization | Yes or No | Question 4 Comment |
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| PacifiCorp | No | GIC models will certainly require additional data beyond what is currently available. PacifiCorp suggests the extension of the Implementation period be 60 months. This would allow time for the software industry to develop viable models, the transformer industry to develop reasonable model data for older, installed transformers and for the industry to develop expertise in the science and tools that are still being developed for this standard. All of these activities must be addressed in order for the actual study efforts to begin successful implementation. |
| Associated Electric Cooperative, Inc. - JRO00088 | 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, 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. |
| Northeast Power Coordinating Council | No | The time frame may not be realistic as it may take considerable time to get the database information from the owners' of those facilities. Also, the software tools may not be fully understood to determine which ones can provide accurate results to the requirement simulations. Even once the software and database information has |

| Organization | Yes or No | Question 4 Comment |
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| | | been procured, the simulation time and development of the Corrective Action Plans would probably take longer than prescribed in the standard. |
| Foundation for Resilient Societies | No | We do not agree with the approach for the transformer thermal assessments. The timeline could be shortened by simply installing hardware blocking devices. |
| ACES Standards Collaborators | No | We believe the overall timeline of four years is too short and burdensome for entities. With limited resources, software, and industry knowledge in this area, it will take entities time to construct the proper data models and conduct these new studies correctly. For smaller entities with limited staff and financial resources, this effort will be a significant challenge. Moreover, affected entities are already engaged in other high-profile NERC-related efforts, such as preparing for the multi-year implementation of Protection System Maintenance, Physical Security, CIP version 5, and the new BES definition. Moreover, there are numerous other standards that will go into effect during this proposed implementation period. We recommend extending the periods identified by the SDT to eight years, to allow industry an opportunity to fully engage in this effort. |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | No | Based on the questionable validity of the conductivity references in the 'white paper' and the lack of technical justification supporting the assumptions made by the SDT in reference to peninsular Florida and other portions of the continental United States, the FRCC RECCF recommends that the implementation plan be modified to allow the FRCC region (and other appropriate areas) to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS and/or Subject Matter Experts (SMEs)can determine the appropriate conductivity value for peninsular Florida (and other appropriate areas). In accordance with the above concern, the FRCC RECCF requests that the implementation of all of the Requirements be delayed for peninsular Florida (and other appropriate areas), pending the re-evaluation of the regional resistivity models by the USGS or SMEs. In the alternative, the FRCC RECCF requests that Requirements R3 through R7 at a minimum be delayed as discussed as |

| Organization | Yes or No | Question 4 Comment |
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| | | the additionally requested re-evaluations are pertinent prerequisites for those Requirements.If the second option is chosen, the FRCC RECCF 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 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. |
| Arizona Public Service Company | No | AZPS would like for the Drafting Team to consider extending the overall Implementation Plan to a 5-year period, rather than the proposed 4-year period as written. Rather than the proposed 12 month period that has been set aside for Requirement 1, we request for the drafting team to allow an overall 24 month period. Much of the industry has no experience with respect to modeling GIC currents and using the new tools being developed; therefore, further education and learning would be needed for those responsible for performing the required studies. This will require significant company resources and the additional 12 months would provide a more reasonable time to accomplish. |
| SERC Planning Standards Subcommittee<br><br>Ameren | No | Detailed modeling data needed to assemble the initial DC models may be problematic for some entities. We are very interested in obtaining the Transformer Modeling Guide, as details to be discussed therein are needed to be able to use our recently obtained GIC module software. One data parameter in this software, a 'K' factor, is needed to be specified correctly in order to correlate GIC current with |

| Organization | Yes or No | Question 4 Comment |
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| | | transformer reactive power losses, which is the entire point of this entire exercise. Errors in specifying this factor on each affected transformer would have a significant impact on the validity of the entire assessment. While the period for producing the models has been increased from 12 months to 14 months in the Implementation Plan, we are still concerned about meeting this time frame. |
| Colorado Springs Utilities | No | If we do not perform a pilot we recommend that R2 implementation be pushed out to 24 months. This will require evalution and procurement of software in addition to the gathering and input efforts required to build the model in the software. R5 and R6 should be moved as well to correspond to the extended timeframe of R2, as recommended above.Is R2 the “dc System Model referenced in the flow chart”? |
| MRO NERC Standards Review Forum<br><br>MidAmerican Energy | No | The NSRF does not agree with the proposed implementation plan for Requirement R1. We believes that 60 days is not enough time to identify the individual and joint responsibilities of the PC and each of the TPs in the PC’s planning area for completing the activities in R2, R3, R4, R5, and R7. Some PCs will require a CFR document that will need to be reviewed and signed by the TP’s management. In our experience with CFR documents, the process requires at least 6 months to complete.Also, the implementation plan as currently proposed, requires the GMD Vulnerability Assessment and Corrective Action Plan to be completed in 48 months. A Corrective Action Plan is to be developed only if the entity’s GMD Vulnerability Assessment, conducted in R3, results in a System that does not meet the performance requirements of Table 1. If the entity needs 48 months to complete its GMD Vulnerability Assessment in Requirement R3, there will not be enough time to complete the Corrective Action Plan in Requirement R7. We suggest that the SDT revise the implementation plan for Requirement R7 to be completed after the GMD Vulnerability assessment. |
| DTE Electric | No | R6.4 indicates that the thermal impact assessment needs to be performed and provided to the responsible entities within 12 months. This is unrealistic based on |

| Organization | Yes or No | Question 4 Comment |
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| | | the analysis required. 36 months, at minimum, would be a more reasonable time frame. Also, it should be clarified that only mitigation recommendations are expected with the assessment. |
| SPP Standards Review Group | No | We have a concern in reference to Requirment R1 and the 60 calendar day time frame. The concern would be not having enough time to determine which entities and responsibilities should be assigned to. The level of communication may have complexity and we would like the language to account for that in the process if possible. We would respectfully request a time extension to 6 months. Our second concern would be in reference to Requirment R6 and the 36 calendar month time frame. Our concern would be working with older equipment (example transformers).... the retrieval and evaluation of data. Also, there is a concern in reference to the GMD Assessments specifically the harmonics and evaluating this data as well. We would respectfully request extending the time frame to 42 calendar month time frame. |
| | | |
| Nebraska Public Power District | No | The 60 calendar day time frame for the R1 requirement is too short. Our concern is the minimal time to determine which entities and subsequent responsibility assignments. The level of communication may have complexity and we would like to account for that in the process if possible. We would request the 60 days be increased to 6 months. Another concern is with Requirement R6 and the 36 calendar month time frame. Our concern is performing the thermal analysis for older equipment which does not have GIC data available or other design data available (for example if manufacturer is no longer available) . Obtaining and evaluating data for older transformers is a major concern. Also, there is a concern in reference to the GMD Assessments, specifically the harmonics and evaluating this data as well. We request extending the time frame to a 42 calendar month time frame. |

| Organization | Yes or No | Question 4 Comment |
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| ISO/RTO Council Standards Review Committee | No | The SRC offers the following comments on the implementation plan.There seems to be a disconnect between the Standard and the Implementation Plan for R1. The implementation plan calls for R1 to be effective 60 days following the approval of the Standard, while the Standard states that the effective date is 12 months following FERC approval. Please modify/clarify what the SDT intends. Is the intent that is it effective 60 days after the 12 month period after FERC approval or just 60 days following FERC approval? In considering clarifications regarding this issue, the SDT should ensure that the time frame for complying with R1 is adequate to facilitate an effective and efficient outcome. Coordinating all relevant entities for this purpose and reaching agreement on the assignment of responsibilities is not a trivial task and appropriate time has to be allowed to accomplish this. The SRC recommends that 4 months be allowed to comply with R1. For R2, having its effective date on the first day of the first calendar quarter that is 14 calendar months after the date that the standard is approved may not be feasible. We suggest 18 calendar months after the date that the standard is approved.Another issue that needs to be addressed is the proper sequencing of the relevant actions under the different requirements. Establishing an appropriate sequence to the actions is required because certain obligations (e.g. planning assessments) require inputs from the outputs of other obligations. For example, the criteria for acceptable voltage limits (R4) is needed in order to conduct the GMD Vulnerability Assessment (R3), and the GMD Vulnerability Assessment needs to be completed in order to have the GIC flow information to provide to the GOs and TOs (R5) so they can do their thermal impact assessments (R6). This involves multiple entities. To ensure the relevant actions under the requirements is coordinated and funtions effectively and efficiently, the SRC recommends the SDT revise the Standard accordingly, and offers the suggested changes to the Implementation Plan:For R3 (complete GMD Vulnerability Assessment), change the implementation timeframe from 48 months to 30 months.For R4 (have criteria for acceptable steady state voltage limits during benchmark GMD event), change the implementation timeframe from 48 months to 30 months.For R5 (provide GIC flow info to TOs & GOs for their transformer thermal |

| Organization | Yes or No | Question 4 Comment |
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| | | impact assessments), change the implementation timeframe from 18 months to 30 months.For R6 (GO & TO conduct thermal impact assessments based on values provided in R5), change the implementation timeframe from 36 months to 42 months. |
| Bonneville Power Administration | No | BPA believes the implementation plan for R1 is too short. BPA's experience in implementing TPL-001-4 R7 suggests coordination takes more than two months to identify the facilities and determine joint or individual responsibility and have an agreement in place to comply with the standard for a large system like BPA. BPA suggests a minimum of six months. |
| Exelon | No | Exelon greatly appreciates the time and effort the SDT has put into this draft but cannot support the draft based on the time frame cited in this requirement.R6.4 states that the thermal assessment should be performed within 12 months after receiving the GIC flow information. Considering the potential number of transformers in scope for Exelon and the data that would need to be requested of the transformer vendors, 12 months is not enough time to perform the thermal assessments. Recommend changing R6.4 to read. 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. |
| Hydro-Quebec TransEnergie | No | This implementation plan is highly dependent on the availability on time of study tools. Please make sure that sufficient delay for tool development is considered and that stages are postponed in consequence. |
| Lincoln Electric System | No | Recommend the time to implement Requirement R1 be extended to 6 calendar months from its current schedule of 60 calendar days. This added time would allow the Planning Coordinator, in conjunction with each of its Transmission Planners, adequate time for the coordination necessary in determining the individual and joint responsibilities.In reference to Requirement R6 and the associated 36 calendar |

| Organization | Yes or No | Question 4 Comment |
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| | | month implementation, recommend extending the time frame to 42 calendar months in consideration of the length of time for retrieval and evaluation of data when working with older equipment (i.e., transformers). |
| American Electric Power | No | Given the unavailability of the generic transformer thermal models and the lack of clarity surrounding the R6 “suggested actions”, it is not possible to determine if the Implementation Plan’s overall timeline of four-years is sufficient. |
| Emprimus | No | We do not support the implementation plan schedule as it is entirely too long. The probability of a solar super storm is agreed to be about 12% within the next 10 years. And state of the art power flow modeling with GIC modules now show that a solar super storm will generate GIC currents of 500 to 3,000 amps in many networks. And these currents levels have the potential to create the largest catastrophe known to mankind. Therefore, the proposed timeline for this implementation plan should be streamlined down to two years or less. |
| | | |
| James Madison University | No | The four-year timeline should include implementation of corrective action. |
| Minnkota Power Corporative | No | See NSRF Comments |
| Independent Electricity System Operator | No | We believe that the proposed timeframe and sequencing in the implementation plan is stringent. GMD modeling data is not commonly available as other data types reported in current MOD standards. Furthermore, entities need to acquire the new models. Requirement 1 should be 90 days, Requirement R2 should be 24 months, R5 should be 36 months and Requirements R3, R4 and R7 should be 60 months. |
| Oncor Electric LLC | No | Regarding R6 we are required to complete the thermal assessment on our transformers within 12 months of obtaining our manufacturer provided GIC capability curves. Since this is dependent on the number of transformers on our system, 12 |

| Organization | Yes or No | Question 4 Comment |
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| | | months may not be enough time to complete the assessment. We kindly request the extension of this period to 24 months. Additionally not being able to influence the time period it will take to obtain our manufacturer GIC capability curves can lengthen the time it takes to complete R5. We recommend that the implementation period for R5 be extended from 18 months to 24 months. |
| Georgia Transmission Corporation | No | Consideration needs to be given to the fact that the majority of entities to which this standard applies will need to "build" a DC model for their own system and then merge the model with other entities in order to create a "DC model of the system". Many entities do not have the expertise or knowledge in building such models and entities may not have adequate resources or software to accomplish this task within the time frame posed. GTC recommends extending the timeline to 8 years in order to ensure the completeness and accuracy of the "DC model of the system" and to complete the assessment. |
| Tri-State Generation and Transmission Association, Inc. | No | Although the changes are an improvement to the standard, Tri-State still believes it may not provide an adequate amount of time for completion. Estimating the harmonics, transformer heating and VAR losses may be more complicated and time consuming. Considering the whole industry will be looking to get information from a limited number of sources the high demand; this may cause the process to move slowly, taking much longer for analysis to be completed than is given by the current implementation plan. Tri-State also believes the effective date for Requirements R3, R4, and R7 should be aligned with the 60 calendar month review time frame. Since R3 states there should be an assessment completed every 60 months, the effective date for R3 should also be 60 months. |
| | | |
| Dominion | Yes | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| Bureau of Reclamation | Yes | The Bureau of Reclamation (Reclamation) appreciates the drafting team's efforts to design a phased approach for completing transformer thermal impact assessments and Corrective Action Plans. Reclamation continues to suggest that R6 should include a 60-month timeframe like R2. As written, it is not clear how often Generator Owners and Transmission Owners are required to conduct thermal analyses of qualifying transformers. |
| Duke Energy | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | |
| Massachusetts Attorney General | Yes | |
| Volkmann Consulting, Inc | Yes | |
| ladwp | Yes | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Hydro One | Yes | The implementation period provides reasonable timelines. |
| American Transmission Company, LLC | Yes | |
| CenterPoint Energy | Yes | As indicated in our previous comment, CenterPoint Energy appreciates the diligent efforts of the SDT and CenterPoint Energy is voting to approve TPL-007-1 as a reasonable set of requirements for GMD planning based upon the current state of the art in this evolving area of study. CenterPoint Energy also agrees that, if the overall four year timeline is maintained, the implementation plan proposed by the SDT is reasonable. That said, based upon CenterPoint Energy's experience with similar processes, CenterPoint Energy believes that 60 days is an unrealistic expectation for thoughtful implementation of Requirement R1. A rushed implementation of that threshold requirement, particularly given the new and evolving state of the art for GMD analyses for most applicable entities, will likely result in ineffective and inefficient implementation of the subsequent requirements of the standard. Stated otherwise, CenterPoint Energy is concerned that rushed implementation of Requirement R1 precludes thoughtful consideration and discussion of how to implement the new standard, potentially dooming the implementation from the very start. CenterPoint Energy recognizes that consideration and discussion of Requirement R1 can begin prior to Commission approval, but unapproved versions of the standard are always subject to changes throughout the approval process. If other stakeholders express similar concerns, CenterPoint Energy recommends that the SDT consider increasing the implementation timeline for R1 and increasing the overall timeline to allow thoughtful consideration and discussion of Requirement R1 by the applicable entities. |
| Idaho Power | Yes | |
| Xcel Energy | Yes | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Manitoba Hydro | Yes | The implementation plan is ok if the scope of transformer thermal assessment is limited to critical transformers with GIC capability curves as described in question 3 above. |
| Northeast Utilities | Yes | |
| LCRA Transmission Services Corporation | Yes | |
| Luminant Generation Company LLC | Yes | |
| Hydro One | Yes | The implementation period provides reasonable timelines. |
| Luminant Energy Company, LLC | Yes | |
| Public Service Enterprise Group | Yes | |
| Ingleside Cogeneration, LP | Yes | |
| Entergy Services, Inc. | Yes | |
| Pepco Holdings Inc | Yes | |
| Texas Reliability Entity | Yes | |
| Public Utiltiy District No. 1 of Cowlitz County, WA | Yes | However, this is uncharted territory.  There should be provision to deal with any unanticipated difficulties. |

**5. Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The SDT has made revisions to conform to changes in the proposed requirements. 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 has reviewed the comments and made changes as appropriate to the revised version of TPL-007-1. In addition, a VRF/VSL justification document has been included in the second posting.

The SDT changed the VRF of Requirement R6 (transformer thermal assessment) from High to Medium to better align with the NERC guidelines for VRFs. The SDT believes that failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System during a 100-year GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or Cascading.

The SDT added a fixed number to the Requirement R6 VSL categories to better describe the impact of noncompliance by a small entity.

Some commenters disagreed with assigning a High VRF to some or all of the requirements in TPL-007-1. They stated that the relative risk of a 1-in-100 year event did not justify a High VRF, or that the NERC guideline for a High VRF did not support the assignment. One commenter recommended a relative risk based on geographical latitude be considered in assigning VRFs. The SDT agrees that Requirement R6 (transformer thermal assessment) should be assigned a Medium VRF consistent with the NERC guidelines for VRFs and has revised the standard accordingly. The SDT does not agree that the VRF for Requirement R3 (GMD VA) and Requirement R7 (CAP) should be lowered. After examining these requirements against the NERC criterion for a High VRF assignment in the planning time horizon, the SDT concluded that failure to meet the requirement 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. In applying the NERC VRF criteria to a requirement in the planning time horizon, the probability of the event being planned for is not a factor. Furthermore, guidelines for setting VRFs are established for consistent application across the Bulk-Power System which precludes basing VRFs on a specific geographic latitude.

Commenters recommended identifying elements or quantities for evaluation instead of pass/fail binary criteria. The SDT reviewed the VSLs and modified the VSL for Requirement R2 (GMD Models) to reflect degrees of compliance. Other VSLs were considered appropriate and consistent with NERC guidelines. The two requirements with pass/fail criteria cannot be separated into component elements or quantities, but rather should be taken as a whole to meet the reliability objective of the requirement. Furthermore, the VSL assignments are consistent with similar requirements in approved TPL-001-4. Pass/fail criteria are assigned a VSL of Severe in accordance with established guidelines.

A commenter recommended modifying the VSLs for Requirement R6 where the percentage basis had a magnified impact on smaller entities. The SDT agrees and has modified the VSLs in the revised standard accordingly. The degree of compliance is now assessed based on a percentage or fixed number as proposed.

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| PacifiCorp | No | Please refer to PacifiCorp's response to Q-7. If the new definition of the BES were incorporated into TPL-007-1, PacifiCorp could support the VRFs and VSLs as listed. |
| Northeast Power Coordinating Council | No | The VRF's and VSL's should be adjusted to reflect the revised threshold(s) proposed in the response to Question 3 - Transformer Thermal Impact Assessment. |
| Foundation for Resilient Societies | No | Because the requirements of the standard are inadequate, we do not agree with the VRFs and VSLs. |
| ACES Standards Collaborators | No | We disagree with several of the SDT's assignment of VRFs with this standard, and believe the most significant level assigned should be Medium. We believe an entity with an incomplete GMD Vulnerability Assessment or poorly documented thermal impact assessment does not significantly impact the reliability of the Bulk Power System. We also believe the SDT should identify measureable criteria for many of the VSLs and not rely just on identifying them as Severe. |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | No | The FRCC RECCF believes that the VRF levels for Requirements R3, R6 and R7 are inappropriately elevated for the potential risk exposure to the BES for a GMD Event and recommends the 'high' designation be lowered to 'medium' for all three (3) requirements. The probability of a severe GMD event occurring has been estimated and analyzed as a 1 in 100 year event and this probability should be taken into consideration when assigning the VRF levels. Additionally, for the majority of the applicable portions of the continent the risk to the BES of a GMD event being severe enough to result in instability, uncontrolled separation, or cascading failures is very low.Assignment of a 'medium' VRF is appropriate for R3, R6 and R7 because, if violated, these requirements could directly affect the electrical state or the capability |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| | | of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, but are unlikely to lead to bulk electric system instability, separation, or cascading failures. |
| Arizona Public Service Company | No | AZPS believes that a binary (i.e. compliant / non-compliant) should automatically fall under the severe category.  Analysis of the impact to the system should still be done and the VSL should reflect that assessment. |
| Colorado Springs Utilities | No | Historical evidence does not demonstrate that any of the VRFs should be "high." Evaluation may be prudent, but potential risk has not proven this to be a high risk to reliability.  A pilot would better demonstrate actual risk. |
| Bureau of Reclamation | No | Reclamation does not believe that R6 should carry a high VRF.  Reclamation believes that the failure to conduct a thermal impact assessment in a timely manner would not likely have a direct impact on the bulk electric system.  Therefore, in accordance with the NERC Rules of Procedure and Sanction Guidelines, Reclamation believes that the VRF should be lowered to low or possibly medium. |
| Emprimus | No | Typically safety margins are on the order of 3 to 5 times the largest load that might expected. In this case, since we are attempting to predict the geo-electric field of a solar super storm that has only occurred in 1859 and 1921 before modern measurement equipment, we should mandate that a safety margin be applied to the mean prediction of 20 V/km by Pullikenen et. al. (2012). So with a safety margin of say 3 times this mean prediction, the standard should be 60 V/km, not 8 V/km as proposed by the drafting team. |
| Liberty Electric Power LLC | No | The percentage basis for R6 strongly affects small entities. A GO with five transformers which are identified receives a severe VSL for completing four of five; a larger entity with one hundred transformers can miss on fourteen and get a high VSL. The impact to the BES is much greater for the larger entity, but the VSL is not.Suggest |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| | | adding "for entities with fewer than ten identified transformers" and making one failure a medium VSL, two a high, more than two severe. |
| James Madison University | No | The standard is so weak that VRFs and VSLs are meaningless. |
| Georgia Transmission Corporation | No | GTC disagrees with the SDT's assignment of VRFs with this standard, and believe the levels should be assigned based on the risks of GICs within geographical latitudes. |
| Associated Electric Cooperative, Inc. - JRO00088 | Yes | |
| Dominion | Yes | |
| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| SERC Planning Standards Subcommittee | Yes | |
| Duke Energy | Yes | |
| MRO NERC Standards Review Forum | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern | Yes | |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| Company Generation; Southern Company Generation and Energy Marketing | | |
| SPP Standards Review Group | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |
| Bonneville Power Administration | Yes | |
| Massachusetts Attorney General | Yes | |
| Volkmann Consulting, Inc | Yes | |
| ladwp | Yes | |
| Hydro One | Yes | |
| American Transmission Company, LLC | Yes | |
| CenterPoint Energy | Yes | |
| Idaho Power | Yes | |
| Manitoba Hydro | Yes | |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| Nebraska Public Power District | Yes | |
| Northeast Utilities | Yes | |
| LCRA Transmission Services Corporation | Yes | |
| American Electric Power | Yes | |
| Luminant Generation Company LLC | Yes | |
| Hydro One | Yes | |
| Luminant Energy Company, LLC | Yes | |
| Ingleside Cogeneration, LP | Yes | |
| Entergy Services, Inc. | Yes | |
| Texas Reliability Entity | Yes | |
| Ameren | Yes | |
| Minnkota Power Corporative | Yes | |
| Independent Electricity System Operator | Yes | |
| Oncor Electric LLC | Yes | |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| Public Utiltiy District No. 1 of Cowlitz County, WA | Yes | |
| MidAmerican Energy | Yes | |
| DTE Electric | | No comment |
| Xcel Energy | | No comment. |

6. **Mitigation Costs. In directing the development of reliability standards, FERC stated their expectation for NERC and the industry to consider the costs and benefits of mitigation measures to address GMD impacts. Proposed standard TPL-007-1 provides performance requirements but is not prescriptive on mitigation strategies or technologies, if any are necessary. The SDT believes this approach, which is consistent with other planning standards, is the most cost effective means to accomplish the directives in FERC's order. Do you agree with the SDT's approach? If you have any recommendations or cost information that you would like the SDT to consider please provide it here.**

**Summary Consideration:** The SDT thanks all commenters who provided input on mitigation costs. The proposed standard addresses the directives for a stage 2 GMD standard in FERC Order No. 779. In the order, FERC stated their expectation that "NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards (P.28)". The SDT has done so by selecting a planning approach for the reliability standard that allows responsible entities latitude to select mitigation from a variety of considerations which may include cost.

NERC Reliability Standards are technology-neutral and focus on the reliability objectives to be accomplished rather than the specific activities to be performed. 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. Furthermore, GMD studies are necessary to achieve the objective of reliable operation during a benchmark GMD event. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations.

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| PacifiCorp | No | Please refer to PacifiCorp's response to Q-7. The requirement for duplicative, iterative studies, using models and data that do not currently exist, for transformers that will not be part of the BES, unreasonably increases the costs to implement this standard without providing any protection to the BES. This valuable effort needs to apply to those elements that will protect the BES and reduce the risk imposed by a GMD event. |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| Foundation for Resilient Societies | No | When the costs of a blackout from a severe solar storm could be in the trillions of dollars and the costs of mitigation are thousands of dollars per location--or less than a billion dollars in total for all EHV transformer locations--a cost-benefit analysis should be required. |
| ACES Standards Collaborators | No | We appreciate the efforts of the SDT to identify what it considers is the most cost effective means to accomplish the directives listed in FERC's order. However, we question if doing nothing to mitigate the risk of GMD events is an acceptable solution as well. Using the materials generated on this topic so far, some entities, based on their geographic location or Physiographic Region, may not need to incur costs and conduct such GMD-related assessments. For entities that are geographically affected, these entities are likely to follow good utility practice and their own risk management policies when balancing mitigation costs with their own business strategies. |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | No | The FRCC RECCF requests the Standard Drafting Team (SDT) to 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 NERC Drafting Team Resources document, Version 1, Effective July 2, 2014, states that each NERC Requirement "should establish an objective that is the best approach for the bulk power system reliability, taking account of the costs and benefits of implementing the proposal" (see page 3 of document). NERC's Whitepaper on the "Implementation Plan of NERC Cost Effective Analysis Process, "CEAP"," states that "[t]he CEAP estimates the implementation costs of a draft Reliability Standard and the effectiveness of the proposed standard if approved and implemented in support of the respective reliability objective." (see page 1 of the document). The Whitepaper continues stating "[c]ost considerations are inherent in the development of Reliability Standards," and "[t]he CEAP affords stakeholders an opportunity to share projected cost information regarding implementation of the draft standards and provides the opportunity to offer alternatives that would be equally, or more |

| Organization | Yes or No | Question 6 Comment |
| --- | --- | --- |
| | | efficient at achieving the reliability objective of the draft standard while also taking into consideration implementation costs.”  (see FRCC RECCF response to Q2 - initial threshold analysis ) Finally, the Drafting Team Reference Manual, Version 2, Effective January 2014, states in the Introduction that the SAR and Standard Drafting Teams will assist in the analysis and/or development of the cost impact analysis and cost analysis respectively (see page 4 of the Manual).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 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.  Consequently, it became apparent that the SDT never analyzed the cost for implementation of this Standard as the SDT was unaware of the cost of purchasing the required modeling software and acknowledged the absence of performing any benefit-to-cost analysis.  The above findings illustrate that the proper analyses for determining benefit to cost ratios have not been performed. Therefore, the FRCC RECCF requests 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 entities. In support of this request the FRCC RECCF 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 and included as an attachment herein. |
| Colorado Springs Utilities | No | SPP Comments only |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| Bureau of Reclamation | No | As written, R7 could be interpreted to allow Planning Coordinators and Transmission Planners to determine Corrective Action Plans without any input or buyoff from Transmission Owners and Generator Owners who may have to bear costs and operational changes associated with corrective actions. Reclamation continues to request that the drafting team include an additional requirement that Planning Coordinators and Transmission Planners to demonstrate that agreement has been reached regarding proposed actions, costs, and timeframes for actions in a Corrective Action Plan that will be completed by Transmission Owners or Generator Owners. |
| DTE Electric | No | More clarity is needed on who selects and funds GIC mitigation measures resulting from the thermal impact assessment. |
| SPP Standards Review Group<br><br>Nebraska Public Power District | No | Our concern in reference to Mitigation Costs associated with the applicability section '4.2.1 Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.' One concern would be how the term ' Facilities' are used in this section. Currently, we can assume that transformers are the main topic of discussion. As we look more to the future, other 'equipment/Facilities' may begin to be included into the process but not specifically defined. We would like to see more specifics on what type of 'equipment/Facilities' that would be defined and associated with this standard. This clarification would give us a better handle on managing our Mitigation Costs. |
| Massachusetts Attorney General | No | R3 points to Table 1 Steady State Planning Events. Footnote 4 of that Table states "Load loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance." For an event that occurs with a 100 year severity level, load loss should absolutely be allowed to be the primary method of achieving required performance. Otherwise this requirement insists on expenditures of dollars of some unspecified amount for unspecified |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| | | measures that have extremely low value that could be better implemented elsewhere. |
| Volkmann Consulting, Inc | No | NERC should perform a cost and benefit study upon completion of the first 4 years of the standard.Once the initial vulnerability assessment is completed, knowledge of the risk and mitigation cost should exist. |
| Manitoba Hydro | No | Costs and benefits of mitigation have not been explored in any of the GMD reference materials that Manitoba Hydro could see. TPL-007-1 is not consistent with TPL-001-4 in that mitigation is required on a 1/100 year event. TPL-001-4 limits mitigation to credible n-2 disturbances, which typically have around a 1/10 year probability (eg. breaker failure). Some of the extreme disturbances recommended to be studied in TPL-001-4 may only have a 1/30 to 1/50 year probability. In addition to the 1/100 year GMD event, it is assumed that reactive power resources will also be unavailable unless a harmonic performance assessment has been completed to verify the resources remain connected. In section 4.3 of the GMD planning guide, the drafting team notes that there are limited tools available to perform appropriate harmonic analysis of a system wide GMD event. Making the conservative assumption that reactive resources are not available, makes the event very conservative.Given the low probability, a 1/100 year GMD event with or without reactive power loss (capacitor banks and SVCs) should be considered an extreme event, and it should be up to the Responsible Entity to perform an evaluation of the possible actions to take to avoid Cascading, for example, however it shouldn't be mandatory for the Responsible Entity to implement those actions. This is a more consistent approach with TPL-001-4.If a Transmission Owner proposes a mitigation for their transformer (eg. neutral blocking device), it should be confirmed by the Planning Coordinator that the mitigation is acceptable and does not create any other adverse impacts on other equipment. |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| Hydro-Quebec TransEnergie | No | Taking into account of the considerable potential expenses, without completed studies and assessment, the cost of mitigation measures can't be evaluated. |
| | | |
| Massachusetts Attorney General | No | Footnote 4 to Table TPL-007-1 states that load loss and or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. I disagree wholeheartedly. If there is an inexpensive way to mitigate, fine, but for a 1 in 100 year or less frequent event, curtailment or load loss perhaps ought to be the primary means of achieving required performance - otherwise this would become a requirement to spend money for little good purpose. |
| Emprimus | No | It appears that the team (SDT) may have concluded that mitigation achieved with equipment will be prohibitively expensive. The extreme opposite is in fact the case, the equipment, a neutral blocking system, is very inexpensive, uses off the shelf components and has been built, extensively tested and demonstrated in a live grid at Idaho National Laboratories. Independent studies by both the University of Manatoba and by EPRI show that the introduction of neutral blocking systems will not cause any unintended consequences for typical power grids. These studies have been made available to the industry within the last year. The equipment for one neutral blocking system is on the order of $300k with an installation cost of $50k or less. Studies performed by PowerWorld LLC for the state of Wisconsin and the state of Maine indicated that adequate protection of a states grid can be achieved with neutral blocking systems on about 50% of the HV and EHV transformers. The cost of this protection is estimated to be a $2 onetime charge per customer. Additionally, when a utility uses noneconomic dispatch whenever NOAA predicts a K7 or larger solar storm, the price of electric is increases since more expensive generation is purchased to avoid outages. But when neutral blocking systems are in place, this noneconomic dispatch procedure can be avoided. So it is estimated that under these |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| | | conditions neutral blocking systems will provide a pay-back with 1 to 2 years. Hence, neutral blocking systems will reduce costs, provide a cost pay back within a few years and then reduce costs thereafter. |
| Public Service Enterprise Group | No | In R7, the responsible entities in R1, which is “Each Planning Coordinator, in conjunction with each of its Transmission Planners,” develop a CAP in response to performance deficiencies identified by them in R3. However, the PC/TP does not have any NERC authority to require any entity to implement the actions in its CAP. That said, the PC/TP may have separate authority outside of NERC such as a FERC-approved RTO/ISO tariff or by agreement with such entities. So that R7 is clear in this regard, we request the first sentence in R7 be modified to recognize this fact. We suggest the following addition to R7:”Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met; PROVIDED, HOWEVER, THAT SUCH RESPONSIBLE ENTITIES MAY ONLY REQUIRE OTHER ENTITIES TO IMPLEMENT THE CAP PLAN AS IT AFFECTS SUCH OTHER ENTITIES’ FACILITIES BY AUTHORITY GRANTED TO SUCH RESPONSIBILIE ENTITIES BY SEPARATE PRIOR TARIFF OR AGREEMENT.” |
| Ameren | No | We believe that this standard, as proposed, would direct all PCs and TPs to perform a large amount of effort to put together the necessary DC GIC models to come to the conclusion that they need not take any significant action for a GMD event. |
| James Madison University | No | Standard should prescribe mitigation strategies to facilitate uniform protection against GMD. |
| Independent Electricity System Operator | No | We do not think the SDT has gone far to remove uncertainty that will adversely affect cost/benefit analysis. For example, the following caveats applied to the GIC capability curve method make it almost difficult for this technique to provide an |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| | | acceptable level of confidence in a planning decision: “While GIC capability curves are relatively simple to use, a fair amount of engineering judgment is necessary to ascertain what portion of a GIC waveshape is equivalent to, for instance, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves have to be developed for every transformer design and vintage .” To promote a consistent application across the interconnection, the SDT should provide more guidance on how to achieve an acceptable level of confidence that mitigating actions are needed. A process to arrive at this level of confidence is presented in our response to Question (2). |
| Northeast Power Coordinating Council | Yes | Hardware based mitigation technologies need to be further proven in test situations before mass deployment. |
| Arizona Public Service Company | Yes | Although AZPS is comfortable with the SDT approach, the SDT might want to consider doing some type of cost assessment of the various technology solutions available to date to inform industry discussions. |
| Dominion | Yes | |
| FirstEnergy Corp | Yes | |
| Tacoma Public Utilities | Yes | |
| SERC Planning Standards Subcommittee | Yes | |
| Duke Energy | Yes | |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| MRO NERC Standards Review Forum | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |
| Bonneville Power Administration | Yes | |
| Exelon | Yes | |
| ladwp | Yes | |
| Hydro One | Yes | Mitigation technologies need to be further proven in test situations before mass deployment. |
| American Transmission Company, LLC | Yes | |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| CenterPoint Energy | Yes | |
| Idaho Power | Yes | |
| Xcel Energy | Yes | |
| Northeast Utilities | Yes | |
| LCRA Transmission Services Corporation | Yes | |
| American Electric Power | Yes | |
| Hydro One | Yes | Hardware-based mitigation technologies need to be further proven in test situations before mass deployment. |
| Ingleside Cogeneration, LP | Yes | The transformer owners will be motivated by economic self interest to mitigate a GMD threat - as long as they have confidence in the planning simulation results. Therefore, it is critical for NERC to find a way to verify actual performance against the computer models. ICLP is aware that it is not easy to record and validate the effect of geomagnetically induced currents on the BES, but the effort is worth it. With other major threats like cyber security looming, the industry needs to allocate scarce resources addressing those which pose the greatest risk to electric service continuity. |
| Entergy Services, Inc. | Yes | |
| Pepco Holdings Inc | Yes | |
| Texas Reliability Entity | Yes | |

| Organization | Yes or No | Question 6 Comment |
|---|---|---|
| Minnkota Power Corporative | Yes | |
| Oncor Electric LLC | Yes | |
| Georgia Transmission Corporation | Yes | |
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| Public Utiltiy District No. 1 of Cowlitz County, WA | Yes | Cowlitz can't envision a need to require entities to find the most cost effective means to address the performance requirements of the Standard. However, it is possible that footnote 4 of Table 1 is not descriptive enough. Cowlitz believes that the performance requirements may need recovery and maximum outage duration metrics included. For low occurrence, high impact events, localized temporary outages must be tolerated to avoid intolerable power costs. This is very difficult to define, but is it out of the question to require limits on local outages? Ultimately, Cowlitz agrees with the method, and cautions against overly descriptive performance requirements. |
| Luminant Generation Company LLC | | While it is unclear how these performance requirements effect a GO, many factors should be considered when developing a mitigation plan. Table 1 is not clear for how it applies to a GO. Costs should be balanced with risk in any mitigation plan.If implemented as written, the standard could allow for a TP to mandate that a GO purchase multiple spare transformers separate and apart from any consideration or costs are risks for the generating unit. |
| Luminant Energy Company, LLC | | While it is unclear how these performance requirements affect a GO, many factors should be considered when developing a mitigation plan. Table 1 is not clear in how it applies to a GO. Costs should be balanced with risk in any mitigation plan.If |

| Organization | Yes or No | Question 6 Comment |
| --- | --- | --- |
| | | implemented as written, the standard could allow for a TP to mandate that a GO purchase multiple spare transformers separate and apart from any consideration of costs or risks for the generating unit. |

**7. 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 for providing feedback. As a result of stakeholder comments, the drafting team has revised performance requirements in Table 1 for added clarity. They have also updated Requirement R3 (previously R4) to give more flexibility to the PC for establishing acceptable voltage performance criteria rather than prescribing that this criteria be voltage limits. A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections:

- **Table 1 Footnote 4 (now 3). Some commenters questioned the implied limits on non-consequential load loss as a means to meeting table 1 performance.** The SDT has revised the guidance in table 1. The new footnote (Footnote 3) reads: Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions.
- **Performance Criteria. Commenters recommended modifying Requirement R4 (now R3; criteria for steady state voltage limits) to allow for future developments in determining voltage stability during a severe GMD event. A commenter recommended the SDT consider additional language to describe what an 'acceptable limit' for steady state voltages would be as specified in Table 1 note d. The SDT supports broadening the voltage criteria requirement (Requirement R3 in the revised standard) to allow PCs to establish criteria for meeting specified performance. The requirement now reads: R3.** Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1.
- **Technical guidance. Commenters asked for additional guidance to be included in the standard or application guidelines, including grounding grid resistance in the GIC model, modeling neighboring systems, and assessing harmonic impacts.** 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 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.
- **Requirements for updating the GMD Vulnerability Assessment. Commenters asked if updates to the GMD VA were required for configuration changes such as the installation of a new line or transformer. Commenters recommended alternate periodicities including a 120-month periodicity or a 36-month periodicity instead of the 60-month periodicity in the proposed standard.** The SDT believes conducting GMD Vulnerability Assessments with a 60-month periodicity will provide the necessary

safeguards for the power system against a 100-year GMD event. They do not believe network changes within this periodicity would significantly change the result for the assessment period or create a vulnerability.

- **Recurrence of Requirement R5 and R6. A commenter recommended adding a subpart addressing recurrence.** The standard specifies a 60-month periodicity for the overall process of the assessments required in TPL-007. Planning entities need the thermal impact assessment information for the GMD Vulnerability Assessment and providing the GIC flow information in Requirement R5 is a necessary step. Owners are required to provide results of the thermal impact assessment with 24 months of receiving GIC flow information. The SDT believes the proposed addition of a periodicity to these requirements is administrative and unnecessary.
- **Use of third-party vendors or consultants. A commenter recommended modifying requirements to allow for a responsible entity to use a third-party.** The standard as written does not preclude the use of third-parties to perform analysis.
- **Assessment iterations to evaluate mitigation. A commenter recommended clarifying the standard to address the necessary time for performing iterations of the GMD Vulnerability Assessment to evaluate mitigation.** The SDT expects that planning entities will factor this into their assessment timeline and does not support a prescriptive time limit. They recognize that some entities will require one or more iterations, while others will not.
- **Underground feeders. A commenter asserted that underground feeders were not affected by GIC and recommended development of a scaling factor for to account for these in power systems.** The SDT recognizes that underground cables are affected by GIC; The standard is not prescriptive in how to model system components, leaving such modeling approaches to the planning entity.
- **Functional Entities. A commenter stated that operating entities needed to be included in the applicability to comply with the FERC Order. A commenter stated that the RC needed to be included as an applicable entity to ensure interconnection-wide perspective on transmission planning.** The SDT has identified appropriate applicable entities for the planning approach consistent with the NERC Functional Model. FERC took no position in the final rule on which entities were to be applicable (P. 82). The RC is not an applicable entity in the planning standard, but they will receive information as a result of planning studies conducted in TPL-007 in accordance with Requirement R7. The RC does not have planning responsibilities according to the NERC Functional Model. The standard as written does not preclude a regional or interconnection-wide study. Applicable Functional entities retain responsibility for requirements of the standard.
- **Applicable Facilities. A commenter recommended including autotransformers in the applicability. A commenter asked if wye-grounded includes solidly wye-grounded, low impedance wye grounded, and high impedance wye grounded windings.** Yes, these power transformers are included in the applicability section.
- **GIC Monitoring. Commenters stated that the standard does not include requirements to monitor GIC, archive data, or validate models using GIC data.** NERC standards do not address installation of specific equipment for any power system application.

Planning Standards define the required reliability outcomes and leave the methods, tools and equipment to the registered entities to determine and implement.

- **Audit, review, or approval of GMD Vulnerability Assessment. A commenter stated that there is no requirement for audit, review, or external approval of GMD Vulnerability Assessment methodology, and that there is no certification process for modeling software.** TPL-007 is in accordance with existing NERC standards related to planning. The techniques used to produce the GMD Vulnerability Assessments are described in various technical guides and are based on the best available information; therefore, the compliance program focuses on fulfilling the requirements of the standard. Planning standards define the required reliability outcomes and leave the methods, tools and equipment to the registered entities to determine and implement.
- **Corrective Action Plans (CAP) requirements. A commenter stated that the proposed standard does not meet FERC order because it does not prohibit CAP from being limited to Operating Procedures or training alone. Commenters recommended modifying Requirement R7 to clearly include a requirement to implement or complete the CAP.** The directive in para 79 of FERC order 779 is met by in Requirement R7 part 7.1 which lists actions which may be included in CAP to achieve acceptable System performance. In the order FERC stated "we clarify that if the GMD vulnerability assessments in the Second Stage GMD Reliability Standards identify potential GMD impacts, while the development of the required mitigation plan cannot be limited to considering operational procedures or enhanced training alone, operational procedures and enhanced training may be sufficient if that is verified by the vulnerability assessments. (P.82)" CAP must include a timetable for implementation as defined in the NERC Glossary.
- **Other functional entity roles in thermal assessments. A commenter recommended that the GO and TO obtain planning entity concurrence on the thermal assessment technique selected in order to avoid an overly conservative model being used. A commenter suggested changing the applicable entity for thermal assessment to the GOP and TOP.** The SDT has assigned responsibility for conducting thermal assessments to owners, which is consistent with the NERC functional model. Asset owners are not precluded from consulting with planning entities during the process, but such consultation is optional.
- **Evidence retention. A commenter proposed that the standard should require data to be retained in perpetuity. A commenter recommended retaining evidence of Requirement R7 (CAP) for as long as the CAP was being implemented.** 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.
- **Administrative (Paragraph 81) Requirements. A commenter recommended removing Requirements R3 (GMD VA) and R7 (Corrective Action Plan) for Paragraph 81 criteria.** The SDT believes these requirements fulfill a reliability objective and are not purely administrative. GMD Vulnerability Assessments must be updated periodically to account for changes and ensure the meets performance requirements. This is consistent with the FERC order which requires 'initial and ongoing assessments' (P. 2)

The SDT also recognizes the reliability benefit in requiring entities to provide CAP to adjacent planning entities, RCs, and other entities identified in the CAP Several commenters have highlighted regional nature of GMD and the need to share information so that the actions of one entity do not negatively impact those of another. R7 part 7.3 provides this obligation.

- **Technical basis for standards. Commenters stated that assessment techniques, models, or tools were not mature enough for a NERC Reliability Standard.** The SDT believes the proposed standard meets the FERC directives and is a technically sound approach to assessing the impact of GMD. The approach outlined in the standard reflects practices that are currently employed and is consistent with the work of the NERC GMD Task Force.
- **Editorial corrections. Commenters provided various editorial corrections that have been included in the revision.**

| Organization | Yes or No | Question 7 Comment |
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| Associated Electric Cooperative, Inc. - JRO00088 | No | AECI has a couple issues with the currently available guidance and rationale on developing DC models. 1. AECI has concerns with the measurement or calculation of station grounding grid resistance.  Various methods have been described in meetings and conferences where concerns were addressed with the current applicability guideline regarding calculation of a value with design modeling when modeling information is not available.  Solutions have been offered outside of what is currently written, proposing a range of values that could be provided to entities without the means to measure or calculate. AECI requests clarity from the SDT specific to calculation of this value when modeling information is not available and if a range of value will be provided for use when all other options are not available. 2. AECI requests further consideration from the SDT in the applicability guide regarding the modeling of neighboring systems.  As written, the three options given do not consider highly interconnected transmission networks which require extensive consideration of neighboring (sometimes internal) systems.  This issue couples with AECI comments regarding the implementation plan. |
| FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF) | No | |

| Organization | Yes or No | Question 7 Comment |
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| FirstEnergy Corp | No | |
| Duke Energy | No | Duke Energy would like to commened the SDT on the work they have done on this project and would like to state that we believe this version of TPL-007- 1 adequately addresses FERC's directives in a way that could be accepted by the industry. |
| Massachusetts Attorney General | No | |
| ladwp | No | |
| American Transmission Company, LLC | No | |
| CenterPoint Energy | No | |
| Idaho Power | No | |
| Nebraska Public Power District | No | In all of the technical presentations, there has not been an example for the thermal analysis for an older transformer without any manufacturer GIC data/curves available. It is mentioned that IEEE has a standard to address this. The issue is GIC thermal curves/GIC data are not available for the majority of the existing power transformers. Even the transformer manufacturers at the technical conferences indicated it is unrealistic to expect GIC curves/data on existing older transformers. As we understand it, the extremely conservative IEEE method will have to be utilized which increases the risks of having to implement likely unnecessary mitigation plans. Even on new transformers being purchased today, when the transformer manufacturer was asked about GIC curves/data, the transformer manufacturer does not understand the requests and could not provide the GIC information. The TLP-007-1 committee needs to provide more information/examples on the thermal |

| Organization | Yes or No | Question 7 Comment |
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| | | transformer assessment for transformers with no available GIC data. In addition, please provide or clarify what transformer data is required to perform this type of thermal assessment. The GMD assessment requirement for other facilities (capacitor banks, protective relays, etc.) is extremely vague. It is unrealistic to require a transmission owner to model their completed transmission system in software such as EMTP. However this is the only type of software today that can model the harmonics and transformer half cycle saturation to determine where other facilities could have potential problems. The TLP-007-1 standard needs to be more specific in what other facilities are to be modeled and reviewed for equipment damage or false protective relay operations or have these considerations removed. How to model these facilities also needs to be addressed, since it not feasible to model the complete transmission system. For example, what level harmonics are acceptable for protective relaying before a false trip occurs? This relay data information is typically not available. |
| LCRA Transmission Services Corporation | No | |
| Emprimus | No | |
| Public Service Enterprise Group | No | |
| Pepco Holdings Inc | No | |
| Georgia Transmission Corporation | No | |
| PacifiCorp | Yes | : PacifiCorp recommends modification of the current language to align with the new revised definition of the BES that became effective on July 1, 2014. The current language of TPL-007-1 includes many elements that have already been excluded |

| Organization | Yes or No | Question 7 Comment |
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| | | from the BES based on the approved definition. The reintroduction of elements which have already been excluded would require unnecessary effort and increase costs for elements that do not affect the reliability of the BES. Removing non-BES elements, such as radial load, would reduce the number of transformers and the iterative process between the GIC assessment and thermal impact assessments and more accurately reflect the actual risk to the grid of a GMD . The PacifiCorp system includes numerous 230-34.5 kV gnd wye-delta-gnd wye distribution substation transformers. In addition the system includes numerous non-BES 230-69 kV gnd wye-delta and gnd wye autotransformers that feed radial 69 kV systems and local networks. An outage of these transformers due to a GMD event would in no way affect the BES. PacifiCorp believes that NERC would be going significantly beyond FERC's authority in attempting to require analysis and mitigation for local distribution facilities |
| Northeast Power Coordinating Council | Yes | Underground Transmission Feeders - The application of the current draft of the standard is problematic for Transmission Owners with underground transmission feeders. It fails to differentiate between overhead transmission lines and underground transmission feeders. While overhead transmission lines may be subject to the direct above ground influences of Geomagnetic Disturbances (GMD's), underground feeders are not. We recommend that an additional scale factor be created within the equation shown in Attachment 1, such that for all underground 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.Model Inputs - Due to the nature of GIC's and the calculation method employed, accurate and timely data on adjacent system equipment is essential to creating and maintaining the System models required by R2. Access to accurate input data on adjacent Responsible Entity(ies) equipment is key to the proper operation of GMD System models. This data is not normally readily available. So, there should be a requirement that all requested adjacent system equipment data be provided by the adjacent Responsible Entity(ies) within 90 days of |

| Organization | Yes or No | Question 7 Comment |
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| | | a written request from another Responsible Entity. Model Results in Adjacent Systems - Adjacent Responsible Entity (ies) should be required to share their model assumptions and adjacent system results with other adjacent Responsible Entity(ies) within 90 days upon receipt of a written request. As currently written, the standard only contemplates the sharing of CAPs, but not any sharing of assumptions and results.Forecast Disagreements - Model results have important implications for Corrective Action Plans (CAPs). Adjacent Responsible Entity(ies) should be precluded from shifting GMD related costs to adjacent systems through inaccurate or inappropriate modelling inputs or computations, and/or cost shifting Corrective Action Plans (CAPs). So, should the respective results forecast--for an adjacent system and the interface elements between adjacent Responsible Entity systems -- be in substantial disagreement, e.g., say by more than 25%, or the forecast project substantial cross boundary impacts, then there should be a process for resolving such forecast differences, e.g., say to within +/-10%, and for mitigating such cross boundary impacts. The Planning Coordinator or Adjacent Planning Coordinators should be engaged to resolve substantially different forecast results to within reasonably acceptable levels. Cost shifting should be addressed and minimized initially through appropriate mitigation on the Responsible Entity's existing system through its CAP.Potential Cost Shifting and Cost Sharing - The potential for cost shifting between adjacent systems is a major concern for industry. Requirement 7.3 only contemplates an exchange of Corrective Action Plans (CAPs). However, how does the drafting team envision ensuring that actions taken in one area (or on one system) do not negatively impact adjacent Responsible Entities, e.g., PJM or ISO-NE CAP's negatively affecting NYISO entities? For example, a PJM CAP might result in GIC's flowing on adjacent NYISO interface and system elements exacerbating a problem in NY. What recourse would a Responsible Entity(ies) have to prevent or minimize such adjacent Responsible Entity actions from negatively impacting their system, and shifting GMD related impacts and costs to their System? After mitigation, residual cost shifting should be addressed through cost sharing payment appropriate to the cost shifting caused by an adjacent Responsible Entity system and CAP.The |

| Organization | Yes or No | Question 7 Comment |
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| | | Rationale Box for R5 references Part 5.3 which is no longer in the draft standard. Please correct Rationale Box wording to reflect the revised Requirement wording and Part numbering.The link to the report referenced in footnote 2 on page 11 is no longer valid.Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx The R1, R2 and R4 VSL's only include a Severe rating. There is no gradation of penalties. The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology.Is there a need to include a time requirement in Requirement R5 in order to account for the 12 calendar months provided for the responsible entity to perform the thermal impact assessment for transformers in accordance with Part 6.4, and still be compliant with the requirement in Requirement R3 of completing a GMD Vulnerability Assessment once every 60 calendar months? Propose to augment Requirement R5 with a requirement for the responsible entity to provide the required geomagnetically induced current (GIC) flow information to be used for the thermal impact assessment specified in the Requirement at least 12 calendar months before completion of the ongoing GMD Vulnerability Assessment cycle, which is due (at least) once every 60 calendar months.The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology. |
| Foundation for Resilient Societies | Yes | Comments on TPL-007-11. Section 4.1 Functional Entities. Because "Load Loss," "Generation Loss", and "Interruption of Firm Transmission Service" will be allowed under the standard, operational entities should also include Transmission Operators, Generation Operators, Balancing Authorities, and Load Serving Entities.2. In regard to FERC Order No. 779, 143 FERC P 61,147 et seq. issued May 16, 2013, this order states, "In the second stage, NERC must submit... one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and ongoing assessments of the potential impact of the benchmark GMD events...." |

| Organization | Yes or No | Question 7 Comment |
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| | | Owners and Operators of the Bulk-Power System include generator owners and generator operators. Moreover, at page 41 of 77 pages, FERC Order No. 779, FERC states: "As noted in NERC's Comments, owners and operators of the Bulk-Power System, as opposed to NERC, will perform the assessments and special attention will be given to evaluating critical transformers (e.g. step-up transformers at large generating facilities);" Para 82 at Page 41 of 77. So, it is mandatory to include both generator owners and operators as having mandatory assessment duties, including those with split or shared ownership and operation. We ask that the Standard Drafting Team reconcile the authority of Reliability Coordinators and Transmission Operators for Operating Procedures under Stage 1 with the authority of other entities, including Generators Owners, in Stage 2 for "Generation Loss" and "Interruption of Firm Transmission Service."3. Section 4.2 Facilities. For consistency with the FERC-approved definition of the Bulk Electric System, the low voltage limit should be 100 kV, not 200 kV.4. The draft standard has no requirement for monitors to measure GIC flows during solar storms nor any requirement to maintain and archive data of GIC flows during storms.5. GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow but there is no requirement to compare modeled GIC flows to measured GIC flows during solar storms. While measured GIC flows may not be immediately available, they can be measured in the future and used to validate GMD Vulnerability Assessments.6. While GMD Vulnerability Assessments are to be provided to Reliability Coordinators, Transmission Planners, and other functional entities, there is no requirement for audit, review, or external approval of GMD Vulnerability Assessment methodology-just audit that that assessments have been performed.7. The draft standard is not compliant with FERC Order 779 because it does not state that Corrective Action Plans cannot be limited to Operating Procedures or training alone.8. There is no certification process for modeling software to be used in preparation of GMD Vulnerability Assessments.9. Section 1.2 Evidence Retention. The draft standard states that "The responsible entities shall retain documentation as evidence for five years" but the solar cycle is 11 years. A more appropriate requirement would be to keep evidence in perpetuity. |

| Organization | Yes or No | Question 7 Comment |
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| ACES Standards Collaborators | Yes | (1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. We appreciate the SDT including Attachment 1, Calculating Geoelectric Fields for the Benchmark GMD Event, and other technical knowledge listed under Guidelines and Technical Basis.(2) However, we believe Requirements R3 and R7 meet Paragraph 81 criteria and should be removed. Requirement R3 requires an entity to reassess its GMD Vulnerability Assessment every sixty months. We believe this standard does not pose a significant impact to the reliability of the Bulk Power System, and Requirement R3 could be classified as a “Periodic Update” under Paragraph 81 criteria. Likewise, an entity would use good utility practice and provide appropriate entities a copy of its Corrective Action Plan in a timely fashion. However, Requirement R7 requires the entity to provide a copy within ninety days. This would be classified as “Reporting” under Paragraph 81. Please revise or remove these requirements from the standard.(3) In Table 1 - Steady State Performance Footnotes, footnote 4 states that non-consequential load loss or curtailment of Firm Transmission Service may be needed to meet BES performance. This may raise similar questions to the TPL footnote ‘b’ issue. Will there be a limit on the non-consequential load loss similar to the resolution done for the TPL footnote ‘b’ issue?(4) Thank you for the opportunity to comment. |
| Arizona Public Service Company | Yes | AZPS would like for the drafting team to align the inclusion threshold with those elements that are considered BES elements, based on the new revised definition of the BES that goes into effect July 1, 2014. In doing so, non-BES transformers should not be included. For example - if there is a transformer with a high-side connected at 200kV or higher with a low-side connected at 69kV, it should not be included unless included based on exception. The standard should also not be applicable to generators that are not included in the BES. |
| Dominion | Yes | R5 Rationale needs to be updated; in which 5.3 needs to be removed. In Part 5.2 ‘Maximum and Amperes’ should not be capitalized, in which they are not defined terms in the NERC glossary. R6/M6 ‘Amperes’ should not be capitalized.Table of |

| Organization | Yes or No | Question 7 Comment |
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| | | Compliance Elements:Page 21 of 24, Lower VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalizedPage 21 of 24, High VSL column, Amperes should not be capitalizedPage 21 of 24, Severe VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalized |
| Tacoma Public Utilities | Yes | There is a potential gap in data sharing because the standard lacks a requirement for Planning Coordinators to share GDM modeling data with neighboring Planning Coordinators or with regional entities. Particularly within the western interconnection, many Planning Coordinators have a small geographic footprint but the GMD analysis requires a regional model. We suggest modifying either the applicability section or requirement R1 to include the either the Regional Entity, the Regional Entity's designee, or the Reliability Coordinator as possible responsible entities for maintaining GIC system models. Some entities have not shared GIC modeling data such as latitude and longitude data because of concern over sharing potential Critical Energy Infrastructure Information per FERC order 630. We would support the STD providing guidance on appropriate sharing of modeling data, including latitude and longitude to two or more decimal places. |
| SERC Planning Standards Subcommittee | Yes | Comment 1: R4 should be modified to allow for future developments in determining voltage stability during a severe GMD event. Specifying steady-state voltage limits as the performance criteria for voltage stability requires that a power flow analysis be performed. Although this is an acceptable approach, in the future more sophisticated methods of determining voltage stability may prove to be better suited for GMD vulnerability assessment. Thus, we recommend modifying R4 as follows:Suggested Wording 1: R4. Each Planning Coordinator and Transmission Planner shall have criteria for determining voltage stability of its System during the GMD conditions described in Attachment 1.Comment 2: The use of load shedding and/or curtailment of Firm Transmission Service to meet performance criteria should be allowed. The |

| Organization | Yes or No | Question 7 Comment |
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| | | reasons for this are two-fold: 1) the intent of the GMD vulnerability assessment is to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System and 2) the probability of the GMD event occurring is 1-in-100 years. Therefore, we recommend modifying #4 in Table 1 as follows:Suggested Wording 2: 4. Load loss as a result of manual or automatic load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Load loss or curtailment of Firm Transmission Service is minimized.Comment 3:The GIC capability of our transmission transformers has not been something typically specified as part of transformer purchases. For any transformers we own for which the GIC value is determined to be 15 A or greater, it will be necessary to contact the transformer manufacturer to determine whether the transformer could withstand the GIC. This situation will likely lead to transformer manufacturers being inundated with requests for such information from all North American TOs. In addition, obtaining such information for transformers whose manufacturer is out of business would be an additional difficulty.Is it the intent of the SDT that the Vulnerability assessment process would be that a new assessment would not be required for the addition of a new EHV line addition, EHV transformer, or replacement of an existing EHV transformer?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. |
| Seattle City Light | Yes | Seattle City Light appreciates the effort of the drafting team to respond to FERC's requests and address industry input. Many concerns have been addressed, but Seattle has remaining concerns in two areas. (1) Use of the Planning Coordinator (PC) to conduct studies: this may be appropriate in most regions but is not appropriate in WECC, which has approximately one-half of all NERC registered PCs. As such, many PCs (such as Seattle) are small and focused only on local considerations. While we |

| Organization | Yes or No | Question 7 Comment |
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| | | could conduct the studies required by proposed TPL-007 on our PC area, the results would not be particularly meaningful because they would address only the area around the city of Seattle. An alternative approach that allows aggregated studies in WECC would be more effective, either at the regional (PEAK RC) or subregional (Northwest Power Pool) levels. (2) Seattle is concerned with the frequency of the studies. A 60-month cycle seems frequent for entities such as Seattle that do not change composition or configuration. We suggest a 120-month cycle for entities that can demonstrate stable system size. |
| Colorado Springs Utilities | Yes | We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. What pilot evaluations have been completed to vet this process with the selected event? We would recommend rolling this process out in a pilot format to refine it and ensure that we are getting the desired evaluation that improves reliability prior to wholesale enforcement. Pilots would need to be conducted in various geographical areas and companies. Then results would be compared and processes refined to reach our reliability goals. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. 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. |
| Bureau of Reclamation | Yes | Reclamation continues to suggest that R6 should include a 60-month timeframe like R2. As written, it is not clear how often Generator Owners and Transmission Owners are required to conduct thermal analyses of qualifying transformers. Reclamation also continues to request that the drafting team clarify why Reliability Coordinators are not included within the scope of the standard. The Question and Answer document did not clarify the rationale for this decision. In the Western Interconnection, the inclusion of the Reliability Coordinator would ensure an |

| Organization | Yes or No | Question 7 Comment |
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| | | interconnection-wide perspective on transmission planning for geomagnetic disturbance events. |
| MRO NERC Standards Review Forum | Yes | |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes | R4 should be modified to allow for future developments in determining voltage stability during a severe GMD event. Specifying steady-state voltage limits as the performance criteria for voltage stability requires that a power flow analysis be performed. Although this is an acceptable approach, in the future more sophisticated methods of determining voltage stability may prove to be better suited for GMD vulnerability assessment. Thus, we recommend modifying R4 as follows:R4. Each Planning Coordinator and Transmission Planner shall have criteria for determining voltage stability of (Remove “acceptable System steady state voltage limits for”) its System during the GMD conditions described in Attachment 1. The use of load shedding and/or curtailment of Firm Transmission Service to meet performance criteria should be allowed. The reasons for this are two-fold: 1) the intent of the GMD vulnerability assessment is to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System and 2) the probability of the GMD event occurring is 1-in-100 years. Therefore, we recommend modifying #4 in Table 1 as follows:4. Load loss as a result of manual or automatic load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be (Remove “needed”) used to meet BES performance requirements during studied GMD conditions. (Remove “but should not be used as the primary method of achieving required performance.”) GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Load loss or curtailment of Firm Transmission Service is minimized (Remove “during a GMD event”). |

| Organization | Yes or No | Question 7 Comment |
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| DTE Electric | Yes | The scope of facilities included should be limited to BES transformers connected at 200kV or higher. Transformers excluded from consideration (instrumentation, station service) should be mentioned in the standard with a clear definition of these types provided. Are the transformer owner's suggested mitigations per R6.3 incorporated into the Corrective Action Plan per R7? It is not clear how thermal assessment results are reviewed and mitigated. |
| SPP Standards Review Group | Yes | In the description of Facilities in the revised standard, the SDT deleted the 'a' in '...with a high side wye-grounded winding...'It would seem that with the 'a' deleted the following term 'winding' should be plural. In fact, that is just what the SDT did in the 4th line of the Summary paragraph in the Screening Criterion for Transformer Thermal Impact Assessment document. Under Applicable Facilities in the Implementation Plan the 'a' is omitted and 'winding' is singular. In the 1st line at the top of Page 7 in the Project 2013-03 (GMD Mitigation) TPL-007-1 Common Questions and Responses the SDT reverts back to the use of 'a' in the facilities description. Further down the page the 'a' is omitted. Regards of which way the SDT decides to go with this phraseology, the SDT should be consistent throughout all documents.Throughout the document, the SDT needs to be consistent with the treatment of 30-, 60- or 90-calendar days by hyphenating the phrase. This also applies to the use of 12- and 36-calendar months.In Requirement R5, use a lower case 'maximum in the 3rd line of Part 5.2. The SDT should capitalize Part throughout the standard and documentation when referring to requirements.In the 2nd line of the 2nd paragraph under Justification in the Screening Criterion for Transformer Thermal Impact Assessment, insert 'Â°C' following '110'. |
| ISO/RTO Council Standards Review Committee | Yes | A. Page 1 - "Description of Current Draft" should state that this is the second draft (not the first draft).B. Page 3, Section 4.2.1 - change "Facilities that include power transformer(s)..." to "Power transformer(s) - power transformers are the only concern.C. Page 5, M3 - the current language is inconsistent with Part 3.3 of R3. To make it consistent, the phrase "any functional entity who has indicated a reliability |

| Organization | Yes or No | Question 7 Comment |
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| | | related need" must be changed  to "and any relevant information shall also be provided to any functional entity that submits a written request and has a reliability related need," which are the words use in Part 3.3 of R3.  Similar comment applies to M7 (similarly inconsistent with Part 7.3 of R7- see comment H below. The SRC recommends adding "any relevant information" to give the responsible entities discretion to effectively manage the dissemination of the information in a vunerability assessment and/or corrective action plan (see comment on R 7.3 below). That information may be sensitive from a reliability (and potentially market) perspective and should be managed accordingly.  By adding "relevant" to this obligation, the responsible entities can provide the necessary data to requesting entities based on need, while limiting access to other sensitive data.D. Page 6, Rationale for Requirement R4 - change "may by different" to "may be different" (typo).E. Page 6, M5 - change "provided geomagnetically-induced current (GIC) flow information" to "provided GIC flow information" (GIC is defined earlier in the Standard, so the acronym can be used here).F. Page 6, Rationale for Requirement R5 - change "The GIC flows provided by part 5.2 and 5.3 are used" to "The GIC flows provided by part 5.2 are used" (5.3 has been deleted).G.  Page 6, Requirement R6 - a provision that requires the TO and GO to provide the results of the thermal impact assessment to the applicable PC/TPs should be added.H. Page 7, M6 - change "as specified in Requirement R6" to "as specified in requirement R6 and have evidence that it provided the thermal impact assessment to entities in accordance with 6.4"I. Page 7, Requirement 7.3 - CAP could call for action by a Transmission Owner (TO) or Generator Owner (GO), therefore 7.3 should be expanded to require provision of the relevant information in the CAP to the TO or GO that has been identified as being required to take action under the CAP.  Change "and to any functional entity that submits a written request and has a reliability related need" to "and any relevant information shall also be provided to any other functional entity referenced in the Corrective Action Plan or that submits a written request and has a reliability related need."  J. Page 8, M7 - change "and to any functional entity who has indicated a reliability related need" to "and to any functional entity that is referenced in the |

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| | | Corrective Action Plan or that has submitted a written request and that has a reliability related need to receive the information.”K. 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. The standard should identify the appropriate entity(ies) to determine if this will occur, and require those entities to provide that information to the entities that are performing the relevant analyses. The SRC believes this determination likely rests with the equipment owners. |
| Bonneville Power Administration | Yes | Table 1, Footnote 4 indicates that load loss should not be used as a primary method of achieving required performance. BPA requests clarification on the primary method. Would Under Voltage Load Shedding (UVLS) be considered a primary method? This event is an extreme event and if assessments show that UVLS schemes would be triggered to prevent voltage collapse, BPA believes this should be allowed.In addition, 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.Finally, BPA reiterates our comments from the informal comment period: BPA feels that the current state and maturity of transformer modeling does not provide modeling which is universally available for all transformers, and less available (if at all) for older transformers that are not of a current design, as would be manufactured today. |
| Exelon | Yes | It would seem that once mitigation actions take place the GMD assessment would need to be re-run to determine the effectiveness of the mitigation, the draft standard doesn’t address analysis of the mitigation actions. Recommend adding a requirement or clairifying text to address the necessary time to perform this iteration. Duration of GIC current application is not provided in a straight forward manner. It would be beneficial if some time limit is assigned with GIC value being provided by the PC / TP to aid in conducting the thermal assessment. Would it be appropriate to assume the GIC present on a transformer be present for maximum of |

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| | | 30 minutes for thermal assessment purposes? Furthermore, can this current be assumed a pure DC current? The document “Screening Criterion for Transformer Thermal Impact Assessment” under Justification references IEEE C57.91-2001 standard. The reference standard should be latest issue of 2011. All of the proposed Transformer Thermal Impact Assessment methods require some involvement by the manufacturer to determine the hot spot thermal transfer functions in order to calculate capability curves. What obligation is the transformer manufacturer under to provide this data, assuming that it is even available? This is especially difficult considering the number of large power transformer manufacturers that are no longer in business. Void of this information, the suggestion is to perform measurements. How would these measurements be performed on an existing transformer already installed in the field? NERC also suggests using generic published values published in Reference 4 “Simulation of Transformer Hotspot Heating due to GIC” IEEE Transactions paper. On what basis is NERC suggesting this as a technically viable alternative?The TPL-007-1 Common Questions and Responses document dated, June 12, 2014, includes a question “Why are generator impacts not specifically addressed in TPL-007?” and provides the following response: “While technical literature has been written on potential generator impacts due to GIC, planning tools are not available to conduct the necessary detailed harmonic analysis. The standard reflects the currently available tools and techniques. The standard does not preclude an entity from conducting additional studies”. Using similar logic, if data or tools are not available to accurately assess thermal impacts on existing transformers for which data is not available, should these not be exempt from assessments? Lack of data will likely require use of overly-conservative assumptions, effectively “penalizing” legacy equipment. It would appear that this position could be applied when the manufacture data and the necessary tools are unavailable to assess the thermal impacts on existing transformers? |
| Volkmann Consulting, Inc | Yes | There has not been any evidence provided by the SDT demonstrating the proper venting and discussion of the Space Weather aspects of this standard. This evidence |

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| | | must be provided prior to Final vote of this standard.The Electric Utility industry has no expertise to judge the Benchmark GMD event. Resting solely on the hand pick Space Science expertise on the SDT is not adequate. If this is adequate why even put the whole standard up for vote, just leave it to the SDT. Proper and inclusive expertise should be sought to review and comment on this technical aspects. This will help in getting FERC's approval. |
| Wisconsin Electric Power Company | Yes | The SDT needs to correct the standard language as identified at the technical conference on 7/17/14. |
| Hydro One | Yes | The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology. |
| Xcel Energy | Yes | It is not clear as to whether an entity can rely on a 3rd party vendor/consultant to carry out R2 & R3 in lieu of maintaining a model 'in house'. Please consider modifying R2 to allow the use of a 3rd party vendor/consultant. |
| ReliabilityFirst | Yes | ReliabilityFirst supplies the following comments for consideration:1. Applicability Sectiona. ReliabilityFirst seeks clarification on whether “autotransformers” are considered as a subset of “power transformers” with section 4.2.1? If yes, ReliabilityFirst believes this should be further clarified. If no, ReliabilityFirst recommends including autotransformers in this section.b. ReliabilityFirst seeks clarification on whether the term “wye-grounded” includes “solidly wye-grounded”, “low impedance wye-grounded”, and “high impedance wye-grounded” windings?c. ReliabilityFirst requests the rationale why the applicability section does not include PC, TP, TO or GO with one or more "long" 200 kV and above transmission lines? Limiting applicability to transformer owners may limit available mitigation. 2. Generic comment related to instances of the word “days” - Throughout the draft standard there are a number of instances that refer to the term “days”. ReliabilityFirst |

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| | | recommends further clarifying the term "days" by preceding it with the term “calendar” or “business” days. 3. Generic comment related to instances of the term “geomagnetically-induced current (GIC)” - Throughout the standard there are many references to the term “geomagnetically-induced current (GIC)”. ReliabilityFirst recommends spelling this term out the first instance it is used and then using the acronym for every other instance.4. Requirement R3, Part 3.1.1. - ReliabilityFirst believes the sub-part should use the NERC Defined term “On-Peak” instead of the undefined term “peak”. This would be consistent with Part 2.1.2 using the term “Off Peak”.5. Requirement R7 - a. Requirement R7 requires the responsible entity to develop a Corrective Action Plan (CAP) but there is no companion requirement for the Responsible entity to “implement” the CAP. Without a requirement for the applicable Entity to “implement” the CAP, theoretically, the CAP could go on in perpetuity without completion and the responsible entity would still be compliant, and their System would continue to not meet the performance requirements of Table 1. ReliabilityFirst recommends the following for consideration: “Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how...”b. ReliabilityFirst recommends removing the language “Examples of such actions include: “since examples should be placed in the guidance section of the standard. ReliabilityFirst recommends modifying Part 7.1 as follows: “List System deficiencies and the associated actions needed to achieve required System performance such as, but not limited to:”c. ReliabilityFirst recommends including the use of automated UVLS in the list under Part 7.1.6. Table 1 Footnote 4 - The Table 1, Footnote 4, which states "the likelihood and magnitude of Load loss... is minimized during a GMD event”, seems to discourage the use of UVLS. ReliabilityFirst seeks clarification on whether it is the SDT’s intent to discourage the use of UVLS. If so, can the SDT provide a justification for the exclusion of UVLS? Furthermore, Table 1, Footnote 4, consists of a number of "may" and "should" |

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| | | statements. Since Table 1 is performance requirements, should these statements in Footnote 4 be "shall" statements? |
| Manitoba Hydro | Yes | Note 4 in Table 1 does not allow curtailment of firm transfers as a primary method of achieving performance. This is a significant "raising of the bar" compared to TPL-001-4. Note 9 of Table 1 for that standard permits curtailment of firm transfers as a permissible correction action as long as there is an appropriate re-dispatch of resources. Note 4 of TPL-007-1 should mirror Note 9 of TPL-001-4. Compliance Monitoring Process 1.1. Compliance Enforcement Authority reads: "As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards."Only the Public Utilities Board (PUB) can enforce Manitoba Hydro's compliance with the NERC Reliability Standards, so this is not accurate for Manitoba Hydro's purposes. That provision should be revised to ensure it is applicable to Canadian entities.A trial period should be given to ensure that the standard as written can in fact be applied and enforced. |
| Hydro-Quebec TransEnergie | Yes | See question 3. As mentioned, it should be considered that the establishment of a GMD benchmark has been done with a new method of analysis and it needs to be validated before requiring compliance based on those estimated values. We encourage the Standard Drafting Team to consider a two level Performance Requirements as proposed in question 3. |
| Northeast Utilities | Yes | Request feedback on the differential focus in the standard between Thermal and Harmonics analysis.SDT Team should consider limiting Requirement 3 part 3.3 to only Reliability Coordinators and Planning Coordinators. |
| American Electric Power | Yes | Paragraph 3 in the "Rationale for Requirement R5" box referenced part 5.3 which does not exist in Requirement 5. Paragraph 3 should read "The GIC flows provided by part 5.2 are used to convert the steady-state GIC flows to time-series GIC data used |

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| | | for transformer thermal impact assessment. Additional guidance is available in the Thermal Impact Assessment white paper:"For clarity, please add "to harmonics" to the end of footnote #3 in Table 1 so foot note #3 reads "Protection Systems may trip due to the effects of harmonics. GMD planning analysis shall consider removal of equipment that the planner determines may be susceptible to harmonics." |
| Luminant Generation Company LLC<br>Luminant Energy 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. Without the curve, the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to 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. |
| CPS Energy | Yes | Please clarify in Requirement R3 that steady-state analysis results should be documented solely in regard to the GMD study, to avoid confusion and duplicative reporting in regards to documentation required by TPL-001. In Table 1, the event listed under the "Event" column should be "the GMD event". The current language states, "Reactive Power compensation devices and other Transmission Facilities removed are a result of the GMD event", which indicates this is a system response to the GMD event, and should not be considered the event in and of itself. If the intention of this language is to generate further analysis due to this system response, there is no need to explicitely state it, as it is already implied by Table 1, Section a, |

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| | | which states Voltage collapse, Cascading and uncontrolled islanding shall not occur, which indicates further analysis is warranted. |
| Hydro One | Yes | The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology. |
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| Entergy Services, Inc. | Yes | Greater flexibility should be provided for transmission planners to account for system changes or modifications that may impact GMD assessment during or after the five year period assessments. In Table 1 on page 8 of TPL-007-1, NERC's Standard Drafting Team should consider the limits associated with modeling the impact of harmonics on protection system trips, it may not be possible to identify all disconnected equipment in planning simulations. An alternative would be to model the impact of harmonics on a case by case basis by modeling the area of interest in detail with EMTP-type programs. |
| Texas Reliability Entity | Yes | Requirement R3:The GMD Vulnerability Assessment (GMDVA) is currently written to cover the Near-Term Transmission Planning Horizon, which means the GMDVA will cover the 12-60 month time period from the date of the GMDVA. However, since the GMDVA is only required every 60 months, the next GMDVA can technically be at 60 months. This means that the efforts to mitigate GMD effects for the year immediately after the second GMDVA (e.g., from 60-72 months) will have little time to be implemented. While it is expected that in the early years (e.g., 0-24 months) of the implementation of this standard there will be little time to implement mitigating activities, the results of the second and later GMDVAs should allow more time to mitigate newly discovered issues. Allowing the GMDVA completion schedule to be the same as the time period it covers may result in reduced reliability, since using the period just after the later GMDVAs does not allow sufficient lead time for |

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| | | mitigation.This can be remedied by either reducing the time period between GMDVA completions (once every 36 months while retaining the Near-Term Transmission Planning Horizon coverage) or increasing the time covered by the GMDVA (96 months instead of the five-year Near-Term Transmission Planning Horizon for the time period covered by a GMDVA that is required every 60 months). Texas RE requests the SDT consider revising the language so the completion schedule is less than the time period it covers. Requirement R4:Texas RE requests the SDT explain what it envisions as establishment of an "acceptable limit" to be (as indicated in Table 1, Steady State item d.) when voltage collapse "shall not occur" (as indicated in Table 1, Steady State item a.). As written, it appears the limit is allowed to be just before the voltage knee where collapse occurs. This would not lend itself to determining compliance for this requirement and may interject reliability issues. In addition, the rationale states that the voltage levels may be different than TPL Standards. Having different voltage level requirements may cause issues with TPL compliance and possibly with reliability. The SDT may want to consider additional language, either within the text of the requirement or an application guideline, to coordinate the acceptable GMD steady voltage limits with the generation undervoltage relay settings requirements in PRC-024 and UVLS systems. Requirements R5 and R6:As written, Requirement R5 and R6 only require one performance of the Requirement (providing geomagnetically-induced current (GIC) flow information and conducting a thermal impact assessment, respectively). The responsible entities will only need to perform the actions in those Requirements once to be compliant. It is unclear whether the SDT intended this result. Texas RE asserts that both requirements need to be performed periodically (i.e., every 60 months, in concert with the GMD Vulnerability Assessment) in order to have a reliability benefit to the BES. Texas RE recommends adding a sub-requirement addressing recurrence.Requirement R7:Requirement R7 does not address completion of a Corrective Action Plan (CAP), only that it be reviewed in subsequent assessments (every five years) until the system meets performance requirements in Table 1. This allows for the possibility that a CAP could go on for extended periods with no conclusion. The third bullet under R7.1 implies that a CAP will have dates for |

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| | | accomplishing the changes needed by including the dates that the Operating Procedures can be eliminated. However, there is no enforceable requirement that needed changes to the BES will be done at specific times. While issues and dates will change with each new set of studies, a CAP for a GMD issue should have dates and/or triggers for each action needed. For example, the corrective action 'add a GMD tolerant transformer at the substation' may not be accomplished if it does not have a due date or trigger to accompany it. Without a completion requirement, enforcement cannot act even when there is a demonstrable reliability risk to the BES. Texas RE suggests the SDT consider adding a trigger such as "when n-1 situations cause excessive loading of the current transformer" or a date such as 2020. The trigger might also be a combination of the two: "when n-1 situations cause excessive loading of the current transformer or 2020, whichever comes first." Compliance Monitoring Process, Section 1.2 Evidence Retention: If evidence retention for responsible entities is five years, it could be difficult to demonstrate compliance. A CAP may take longer than five years to complete. This puts a burden on the entity 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. The limited evidence retention period also has an impact on determination of VSLs. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained. Texas RE recommends revising the evidence retention to cover the period of two GMDVAs. |
| Ameren | Yes | The GIC capability of our transmission transformers has not been something typically specified as part of transformer purchases. For any transformers we own for which the GIC value is determined to be 15 A or greater, it will be necessary to contact the transformer manufacturer to determine whether the transformer could withstand the GIC. These situations will likely lead to transformer manufacturers being inundated with requests for such information from all North American TOs. In addition, obtaining such information for transformers whose manufacturer is out of |

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| | | business would be an additional difficulty. The performance requirements described in the definition, in the background, and in Table 1 are not clear and appear to be conflicting. (See Table 1 steady state performance requirement a, b, and d.) For additional reactive load losses and outage of capacitor banks caused by GIC, how would load be lost except for voltage collapse? We believe that the emphasis should be placed on widespread voltage collapse and not simply local voltage collapse issues that may occur for equivalent Category C type of events.Our understanding of the Vulnerability assessment process would be that a new assessment would not be required for the addition of a new EHV line addition, EHV transformer, or replacement of an existing EHV transformer.We believe that details for performing the calculations and assessments are still being developed, and are in its infancy at this stage, and are far too early to codify into a standard. |
| Liberty Electric Power LLC | Yes | R7.3 states the CAP should be provided to 'adjacent Planning Coordinators, adjacent Transmission Planners,'. A GO does not have the wide area view to determine which PCs and TPs would be impacted by the CAP. The requirement should be to provide the CAP to the RC, who can then determine which entities need the information. The requirement should also include giving notice to the GO or TO that the CAP has been sent to those adjacent PCs ans TPs, and provide the CAP owner with the names of the PCs and TPs along with contact information. |
| James Madison University | Yes | Comments on NERC's draft GMD Benchmark ReportI have grave concerns about the validity of NERC's April 2014 "Benchmark Geomagnetic Disturbance Event Description" report and wish to alert you to major technical problems with its contents. Because of significant flaws in the report, the GMD Benchmark Event should not be approved in its present form. Re-investigation and revision is needed. The text of my letter below speaks to major concerns. I have also included an attachment that provides specific comments by paragraph based on my review and methods of 'extreme event' probability expert, Dr. Charles T. C. Mo.To begin with, the NERC report misuses available statistics on solar storm environments. The report |

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| | | employs an incomplete data base that uses a 20 year time window to make inferences about the probability of 100 year effects. In effect, the report assumes the sun behaves the same during all solar cycles, an assumption known to be erroneous. The report bases its conclusions on subjectively extrapolated tails of probability distributions using incomplete data sets. This methodological error effectively closes the door on preparedness for “outlier” storms such as the 1869 Carrington event or the 1921 Railroad Storm.The NERC report contains no reference to or rationale for dismissing measured geoelectric fields and GIC data that are far in excess of what the GMD Benchmark would predict.Statisticians often assess risk using a number called “expected loss,” which is derived by multiplying the probability of an accident times the value of the loss caused by the accident. This approach is implicit in NERC’s concern about reducing the probability of a major GMD event- viz. by using a 20 year interval of relatively mild solar storms, and reducing the expected loss by minimizing the expected 100 year peak electric field, and by inventing the concept of limited-area solar storm electromagnetic “hot spots.” A prudent person would base decisions involving high consequence events on factors that go beyond the expected loss.A better approach for low-likelihood, high consequence events has been developed by Professor Yacov Haimes at the University of Virginia. In his “Partitioned Multi-Objective Risk Method” or PMRM approach , Haimes argues that it is necessary to account for catastrophic events separately from ordinary accidents. Rare but extreme loss catastrophes may have a manageable expected loss, but that does not mean that accepting their risk is justified.[i] As an illustrative example, a catastrophe involving a 100 year Carrington-class solar storm could conceivably shut down the U.S. economy for 1 year or more. The value of the economic loss would be one GNP or approximately 17 trillion dollars. If the probability is 1% per year (the historic probability is in this ballpark), the expected loss would be $170 billion, which is relatively small in comparison to the annual U.S. federal budget. But the PMRM approach would argue that because hundreds of millions of lives are at risk and because continuity of national governance is at risk, such a catastrophe must never be allowed to happen. In summary, even though a Carrington Event-caused shut- |

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| | | down of a continental-scale portion of the North American electric power grid is unlikely in any single year, it is also totally unacceptable. Based on Professor Haimes' arguments and other reasons, I submit that the entire North American grid should be protected against GMD if FERC and NERC are serious about safeguarding the American public. Reasons include:1. Uncertainties in magnitude of worst-case GMD fields are at least a factor of ten. Southerly latitudes may well be exposed to much larger GMD than predicted by the NERC standard de-rating formula. 2. Protective measures are commercially available and cost-effective. Neutral current blocking devices can accommodate a factor 5-10 excursion in the field magnitude above the NERC 8 KV bogey proposed in the draft standard. 3. The entire North American grid is susceptible to exposure to the effects of a nuclear EMP E3 that outstrips the NERC 8 KV bogey by a factor of 10. Nuclear E3, unlike GMD, increases at southerly latitudes. In the event of a nuclear EMP event, portions of the grid unprotected against GMD will succumb to EMP-E3 effects. It is highly prudent and cost-effective to address EMP-E3 and GMD protection concurrently - otherwise another highly redundant and unnecessary round of costly protection assessment and implementation will be required.In closing, we need to be very careful where the survival of millions of Americans and the breakdown of our national governance is at risk. There is reasonable certainty that GMD storms and EMP events will occur with magnitude in excess of the Benchmark GMD Event. These high-magnitude events will render moderate protection designed to a defective GMD Benchmark completely ineffective. Implementation of the current draft GMD Benchmark will leave us susceptible to continental-scale grid failures from solar GMD and EMP. I recommend that NERC incorporate Yacov Haimes' PMRM approach to protect our society. Finally, I urge you to send the current Benchmark Geomagnetic Disturbance Event Description document back to the Standard Drafting Team for revision.Sincerely, George H. BakerProfessor Emeritus and Former Director, Institute for Infrastructure and Information Assurance, James Madison UniversityCongressional EMP CommissionAttachment: Detailed comments on Project 2013-03 Benchmark Geomagnetic Disturbance Event Descriptionâ€ƒAttachment 1NERC Project 2013-03 |

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| | | Benchmark Geomagnetic Disturbance Event DescriptionDetailed CommentsGeorge H. Baker and Charles T.C. Moo Page 6, paragraph 4. Do you include all data in the 100 year time span? If not, another layer of statistical inference is needed based on a model that includes the sampling nature of the known data vs. the actual occurrences. The analysis must based on all available data and objectively and truthfully exclude any subjective data truncation.o Page 6, formula (1). An added factor is needed to account for shoreline enhancement. Many generator stations and associated transformers are located along edge of water bodies.o Page 7, paragraph 1, sentence 1. Should include data going back as far as possible even if 100 year span is not available. Look for and include data from outlier events.o Page 7, paragraph 2. ï,§ The latitude scaling was not explained in the earlier formula (1) discussion. Is this just a cosine law or empirical? Show the relation curve and error range.ï,§ The 8kv/m level is lower than historically measured peak GMD field values.ï,§ You need to add the approximate low frequency formula that maps dB/dt to E\|\| including its dependence on earth conductivity and effective ground depth.o Page 9, Statistical Considerations, paragraph 1.ï,§ You dismiss the Carrington event from the data base since there is inadequate information to relate dB/dt to E field. You made no mention of the 1921 Railroad Storm where dB/dt levels. Data from this storm will be very important to include since it was a high-side outlier.o Page 9, Statistical Considerations, paragraph 2. ï,§ Explain why you see a correlated relationship between DST and storm strength.ï,§ Again, why have you not referenced the 1921 Railroad Storm?ï,§ Per your statement, “These translate to occurrence rates of approximately 1 in 30-100 years,” please include the confidence level or Bayesian coverage if a subjective Bayesian formulation is used. Also, you need to explain the "translate" model, e.g. do these events have Poisson independent arrival times of constant rate, or what? In any case, extrapolating from a 20 year data base to 600 years assumed a strong stationarity of the event occurrences. Proper statistical inference from such events needs be accompanied by a reduced confidence since the extrapolated time span is significantly longer than the data time window. o Page 10, Figure I-1. Please provide a reference for this figure. Where in the refereed |

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| | | professional journals have you seen the “hot spot” concept developed?o Page 11, paragraph 1 and figure I-2. You need to convince the reader/user. How do these four 10.0 to 18.9 year coverage curves infer complete 100 year behavior?o Page 11, Figure I-2. Behavior of the tails of these distributions is not shown. Extreme values of the low end of probabilities are subject to large uncertainties.o Page 12, Paragraph 1. The fundamental flaw of following the 20 year model fit regression type statistical analysis (and thus claim to infer from one cycle the sunspot behavior of many other cycles and accordingly infer solar behavior over a much longer time span) is that your approach assumes that the model parameters are actually the same set of constants in all cycles. As a result, your estimates and inferences from data in just one solar cycle, or in two cycles is equivalent to expanding them to represent one much larger data set, i.e., you are assuming parameters computed based on one cycle immediately valid for any other cycle. But if these parameters are themselves random sample realizations from cycle to cycle, then the analysis is totally invalid. As an extreme example: if within one 11 year cycle you have a very large sample set, then you can estimate these parameters with near certainty in a almost point value estimate. But then you have no information of their value in another cycle. Realistically, you must physically model these parameters as random variables themselves, such that each cycle contains a parameter set of their realization. Then use these sets to develop your estimates. The proper approach is mathematically more complicated but a physically more realistic two layer statistical inference problem. o Page 12, Figure I-3. The sample time window is too narrow to infer 100 year behavior.o Page 16, paragraph 1. Not clear how the intensification factor of 2.5 was derived. Please explain and provide reference.o Page 16, Figure I-6. It is important to take into account where the locus of transformers within the grid. If the transformers are positioned at choke points, the loss of small number can be significant. |
| Minnkota Power Corporative | Yes | The Definition in TPL-007-1 for Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment refers to “voltage collapse, Cascading or localized |

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| | | damage of equipment." In Table 1-Steady-State Planning Events refers to "Cascading and uncontrolled islanding shall not occur." Why are they different? |
| Independent Electricity System Operator | Yes | To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed service; the standard should require Generator and Transmission Owners to select a thermal analysis technique acceptable to Transmission Planners and Planning Coordinators. This is necessary to mitigate a risk that asset owners would gravitate towards simple but overly-conservative techniques that would result in too much equipment removed from service. |
| Oncor Electric LLC | Yes | Oncor commends the SDT for providing the 15A threshold which allows flexibility for transmission planners from assessing unnecessary equipment. However for the equipment that must be assessed there are a few items that, as mentioned in our response to question 2, can better equip us for performing our study. |
| Tri-State Generation and Transmission Association, Inc. | Yes | Tri-State believes R6 requiring each TO and GO to conduct a thermal impact assessment for each jointly owned applicable transformer would be a duplicative and unnecessary requirement. This will require multiple analysis of jointly owned facilities and will be a waste of resources for entities. Tri-State suggests the operators be in charge of running the thermal impact assessment and sharing that to all the appropriate owners. TOs and GOs should be responsible for acknowledging that they received the assessment and keeping for the required period of time. This would significantly reduce the number of assessments completed while keeping the goal of the requirement. |
| Public Utiltiy District No. 1 of Cowlitz County, WA | Yes | For smaller entities who lack experienced modeling engineers, the guidance and white papers are high level and very difficult to grasp if not impossible. Contract engineering consultant work will be a must, however a basic understanding of key concepts would be a great help in assuring the procurement of good engineering expertise. Cowlitz suggests a white paper addressing this would be most helpful. |

| Organization | Yes or No | Question 7 Comment |
|---|---|---|
| MidAmerican Energy | Yes | MidAmerican is concerned that the requirement to analyze the harmonic impacts on relaying when no such methods are resonably available is burdensome. Prior to finalizing the standard the SDT should provide guidance on how to do this or, at least, what should be considered as compliant with this requirement. |
| Portland General Electric Company | Yes | Portland General Electric appreciates the efforts of the drafting team in developing this standard. However, our primary concern is that in the WECC due to the size of the region, the RC should be included as an applicable entity since they would have the wide area view of the region and could better facilitate the coordination of studies and reviews amongst entities. |
| PPL NERC Registered Affiliates | | 1. The Rationale for Requirement R6 states that "The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means." Regarding the first of these alternatives, we (and probably most other entities) have no manufacturer capability curves for geomagnetically-induced current (GIC), nor would it be reasonable to expect that such information will ever be made available for equipment that was designed and manufactured in most cases decades ago. NERC's Transformer Thermal Impact Assessment white paper states for the second alternative (simulation), "hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers," which are unavailable as stated above, or, "Conservative default values can be used (e.g. those provided in [4]) when specific data are not available." Reference 4 is an IEEE technical paper by Marti et al, and it shows transfer functions, "as determined by the manufacturer," for a single-phase transformer ("Transformer A") in Fig. 1 and as determined during acceptance testing for another single-phase unit ("Transformer B") in Figure 5. There are no "conservative default values" presented for three-phase transformers, nor any suggestion that the Transformer A and B curves can be applied with confidence for all single-phase equipment. The Transformer B information is in fact unusable, since the unit operated for only one minute at a GIC level above the TPL-007-1 screening |

| Organization | Yes or No | Question 7 Comment |
|---|---|---|
| | | threshold value of 15 A.The "e.g." in the Transformer Thermal Impact Assessment white paper citation above means "for example," indicating that sources of conservative default values other than the Marti paper may be used. None are listed in the References section of the white paper, nor do we know of any open literature containing a wide-ranging database of this information. Scattered bits and pieces may be found, such as the examples shown in NERC's GMD publications, but these collective inputs are greatly inadequate given the statement in the white paper that "manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves have to be developed for every transformer design and vintage."Thermal impact assessment via simulation is therefore not a viable option, leaving only, "other technically justified means." The Transformer Thermal Impact Assessment white paper provides no indication of what such means may consist-of, nor are we able to imagine any. Special sensors such as those evidently applied when testing Transformer B of the Marti paper could not be installed for equipment in the field, nor would testing of every transformer in North America prove practical. NERC's Geomagnetic Disturbance Planning Guide of Dec. 2013 states that one can use, "defaults [transfer functions], such as the ones shown in the NERC Transformer Modeling Guide, but this document has never been issued. There is in summary no practical means of achieving compliance with R6 of TPL-007-1. We recommend that NERC obtain conservative default GIC curves covering all types and sizes of transformers affected by this standard, and then publish this information in the promised Transformer Modeling Guide. |
| Sacramento Municipal Utility District | | SMUD advocates for the GMD study requirements be performed or optioned for conducting the studies at a Regional level or as part of a Task Force or a Working Group for the following reasons: o Regional level developed model will provide a better considered analysis than by the individual PCs, TOs, or GOs; o Study results will be better analyzed and interpreted by equipment owners instead of individual entities' interpretation of the results; o A single report produces for all Regional members instead of individual report from each Members could lead to inconsistent |

| Organization | Yes or No | Question 7 Comment |
|---|---|---|
| | | results/conclusions/recommendations;  o Entities' resources can be significantly reduced by participating in Regional process instead of perform the numerours studies that are currently contemplated in the standard. |

**END OF REPORT**

# Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard

**A White Paper by:**

**John G. Kappenman, Storm Analysis Consultants**

**and**

**Dr. Willam A. Radasky, Metatech Corporation**

**July 30, 2014**

**Executive Summary**

The analysis of the US electric power grid vulnerability to geomagnetic storms was originally conducted as part of the work performed by Metatech Corporation for the Congressional Appointed US EMP Commission, which started their investigations in late 2001. In subsequent work performed for the US Federal Energy Regulatory Commission, a detailed report was released in 2010 of the findings[11]. In October 2012, the FERC ordered the US electric power industry via their standards development organization NERC to develop new standards addressing the impacts of a geomagnetic disturbance to the electric power grid. NERC has now developed a draft standard and has provided limited details on the technical justifications for these standards in a recent NERC White Paper[22].

The most important purpose of design standards is to protect society from the consequences of impacts to vulnerable and critical systems important to society. To perform this function the standards must accurately describe the environment. Such environment design standards are used in all aspects of society to protect against severe excursions of nature that could impact vulnerable systems: floods, hurricanes, fire codes, etc., are relevant examples. In this case, an accurate characterization of the extremes of the geomagnetic storm environment needs to be provided so that power system vulnerabilities against these environments can be accurately assessed. A level that is arbitrarily too low would not allow proper assessment of vulnerability and ultimately would lead to inadequate safeguards that could pose broad consequences to society.

However from our initial reviews of the NERC Draft Standard, the concern was that the levels suggested by NERC were unusually low compared to both recorded disturbances as well as from prior studies. Therefore this white paper will provide a more rigorous review of the NERC benchmark levels. NERC had noted that model validations were not undertaken because direct measurements of geo-electric fields had not been routinely performed anyway in the US. In contrast, Metatech had performed extensive geo-electric field measurement campaigns over decades for storms in Northern Minnesota and had developed validated models for many locations across the US in the course of prior investigations of US power grid vulnerability[3]. Further, various independent observers to the NERC GMD tasks force meetings had urged NERC to collect decades of GIC observations performed by EPRI and independently by power companies as these data could be readily converted to geo-electric fields via simple techniques to provide the basis for validation studies across the US. None of these actions were taken by the NERC GMD Task Force.

It needs to be pointed out that GIC measurements are important witnesses and their evidence is not being considered by the NERC GMD Task Force in the development of these standards. GIC observations provide direct evidence of all of the uncertain and variable parameters including the deep Earth ground response to the driving geomagnetic disturbance environment. Because the GIC measurement is also obtained from the power grid itself, it incorporates all of the meso-scale coupling of the disturbance environments to the assets themselves and the overlying circuit topology that needs

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[1] *Geomagnetic Storms and Their Impacts on the U.S. Power Grid* (**Meta-R-319**), John Kappenman, Metatech Corporation, January 2010. Via weblink from Oak Ridge National Lab, *wttp://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml*

[2] NERC Benchmark Geomagnetic Disturbance Event Description, *http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Benchmark_GMD_Event_April21_2.pdf*

[3] Radasky, W. A., M. A. Messier, J. G. Kappenman, S. Norr and R. Parenteau, "Presentation and Analysis of Geomagnetic Storm Signals at High Data Rates", IEEE International Symposium on EMC, August 1993, pp. 156-157.

to be assessed. Separate discreet measurements of geo-electric fields are usually done over short baseline asset arrays which may not accurately characterize the real meso-scale interdependencies that need to be understood. The only challenge is to interpret what the GIC measurement is attempting to tell us, and fortunately this can be readily revealed with only a rudimentary understanding of Ohm's Law, geometry and circuit analysis methods, a tool set that are common electrical engineering techniques. Essentially the problem reduces to: *"if we know the I (or GIC) and we know the R and topology of the circuit, then Ohm's law tells us what the V or geo-electric field was that created that GIC"*. Further since we know the resistance and locations of power system assets with high accuracy, we can also derive the geo-electric field with equally high certainty. These techniques allow superior characterization of deep Earth ground response and can be done immediately across much of the US if GIC measurements were made available. Further these deep Earth ground responses are based upon geological processes and do not change rapidly over time. Therefore even measurements from one storm event can characterize a region. Hence this is a powerful tool for improving the accuracy of models and allows for the development of accurate forward looking standards that are needed to evaluate to high storm intensity levels that have not been measured or yet experienced on present day power grids. Unfortunately this tool has not been utilized by any of the participants in the NERC Standard development process.

It has been noted that the NERC GMD Task Force has adopted geo-electric field modelling techniques that have been previously developed at FMI and are now utilized at NRCan. The same FMI techniques were also integrated into the NASA-CCMC modeling environments and that as development and testing of US physiographic regional ground models were developed, efforts were also undertaken by the USGS and the NOAA SWPC to make sure their geo-electric field models were fully harmonized and able to produce uniform results. However, it appears that none of these organizations really did any analysis to determine if the results being produced were at all accurate in the first place. For example when recently inquired, NRCan indicated they will perhaps begin capturing geo-electric field measurements later this year to validate the base NERC Shield region ground model, a model which provides a conversion for all other ground models. In looking at prior publications of the geo-electric field model carried out in other world locations, it was apparent that the model was greatly and uniformly under-predicting for intense portions of the storms, which are the most important parameters that need to be accurately understood.

In order to examine this more fully, this white paper will provide the results of our recent independent assessment of the NERC geo-electric field and ground models and the draft standard that flows from this foundation. Our findings can be concisely summarized as follows:

- Using the very limited but publicly available GIC measurements, it can be shown how important geo-electric fields over meso-scale regions can be characterized and that these measurements can be accurately assessed using the certainty of Ohm's Law. This provides a very strict constraint on what the minimum geo-electric field levels are during a storm event.

- When comparing these actual geo-electric fields with NERC model derived geo-electric fields, the comparisons show a systematic under-prediction in all cases of the geo-electric field by the NERC model. In the cases examined, the under prediction is particularly a problem for the rapid rates of change of the geomagnetic field (the most important portions of the storm events) and produce errors that range from factor of ~2 to over factor of ~5 understatement of intensity by the NERC models compared to actual geo-electric field measurements. These are enormous errors and are not at all suitable to attempt to embed into Federally-approved design standards.

- These enormous model errors also call into question many of the foundation findings of the NERC GMD draft standard. The flawed geo-electric field model was used to develop the peak geo-electric field levels of the Benchmark model proposed in the standard. Since this model understates the actual geo-electric field intensity for small storms by a factor of 2 to 5, it would also understate the maximum geo-electric field by similar or perhaps even larger levels. Therefore this flaw is entirely integrated into the NERC Draft Standard and its resulting directives are not valid and need to be corrected.

The findings here are also not simply a matter of whether the NERC model agrees with the results of the Metatech model. Rather the important issue is the degree that the NERC model disagrees with actual geo-electric field measurements from actual storm events. These actual measurements are also confirmed within very strict tolerances via Ohm's Law, a fundamental law of nature. The results that the NERC model has provided are not reliable, and efforts by NERC to convince otherwise and that utilization of GIC data cannot be done are simply misplaced. Actual data provides an ultimate check on unverified models and can be more effectively utilized to guide standard development than models because as Richard Feynman once noted; "Nature cannot be fooled"!

**Introduction to NERC Model Evaluation and Validation Overview**
A series of case study examples will be provided in this White Paper to illustrate the evaluation of geo-electric fields derived from GIC measurements across the US electric power grid. These derived geo-electric field results will then be compared to the NERC estimated geo-electric fields for the same storm events and scenarios. There are an important number of underlying principles to this analysis that can be summarized as follows:

- Using past storms and by modeling detailed power networks and comparing to GIC measurements at particular locations is the best way to validate overall storm-phenomena/power grid models. It accounts for the "interpolation" of the incident measured B-fields (including the angular rotation of the fields with time), the accuracy of the ground model used, the coupling to the power network, and the computation of the current flow at the measurement point.

- Experience has shown that over times of minutes, the geomagnetic field will rotate its direction and therefore every transformer in a network will have a sensitivity to particular vector orientations of the field, and the maximum current measured at a given transformer location will be a function of the rate of change intensity of the geomagnetic field, the resulting geo-electric field this causes and the angle of the field as it changes over the storm event. This is why the rate of change (dB/dt) and GIC at a single transformer will not scale perfectly with the maximum value of dB/dt, but taking into consideration all of these topology and orientation factors, a highly accurate forensic analysis can be performed.

- Geomagnetic storms are not steady state events, rather they are events with aperiodic extreme impulsive disturbances that can occur over many hours or days duration. Modeling these events to derive a geo-electric field is challenging but readily achievable. Since these events are time domain problems, modeling solutions using time-domain methods are recommended. The NERC modeling methods that will be evaluated here have generally been developed using Fourier transform frequency domain methods. In these implementations of Fourier methods, the primary question is the accuracy in dealing with the phase of the Fourier transforms.

- When referring to impulsive geomagnetic field disturbance events, these are typically multiple discrete events with times of several minutes. Note that the collapse of the Quebec power network in March 1989 occurred in 93 seconds. Clearly times of only a few minutes are important and it is vital that the geo-electric field intensity of these transients be accurately portrayed and not understated in a Design Standard type document. For example, a 10 meter dyke defined by the standard does no good, if the actual Tsunami height is 15 meters. Any efforts to claim that models that depict some satisfactory averaging over extended time periods as being sufficient must be vigorously refuted, as these peak inflection points are the most vital aspects of the storm environments that must be accurately determined.

**Simulation Model Validation – Maine Grid Examples**
In the analysis carried out for the FERC Meta-R-319 report, extensive efforts were undertaken to verify that the simulation models for the US power grid were providing sufficiently accurate results. One of the primary approaches that were utilized to test these models were to perform simulations for forensic analysis purposes and to compare the results with discrete measurements that were available.

One of the forensic simulations was conducted on the Maine grid and provided important verification of the ability of the model in that portion of the US grid to produce accurate estimates. Figure 1 provides a plot of the results of this simulation showing the "Calculated" versus "Measured" GIC (geomagnetically induced current) at the Chester Maine 345kV transformer. This was for a storm which occurred on May 4, 1998 and was driven by the large scale storm conditions as shown in Figure 2.

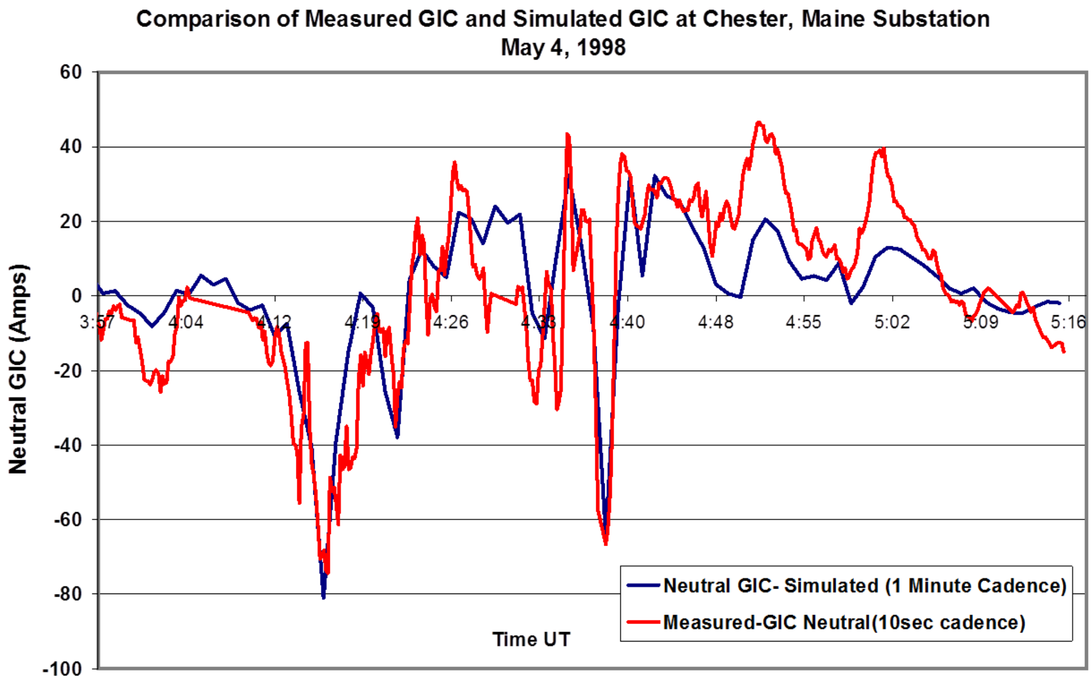


**Figure 1 – Plot showing comparison of Simulated versus Measured GIC at Chester Maine 345kV transformer for May 4, 1998 geomagnetic storm. (Source – Meta-R-319)**

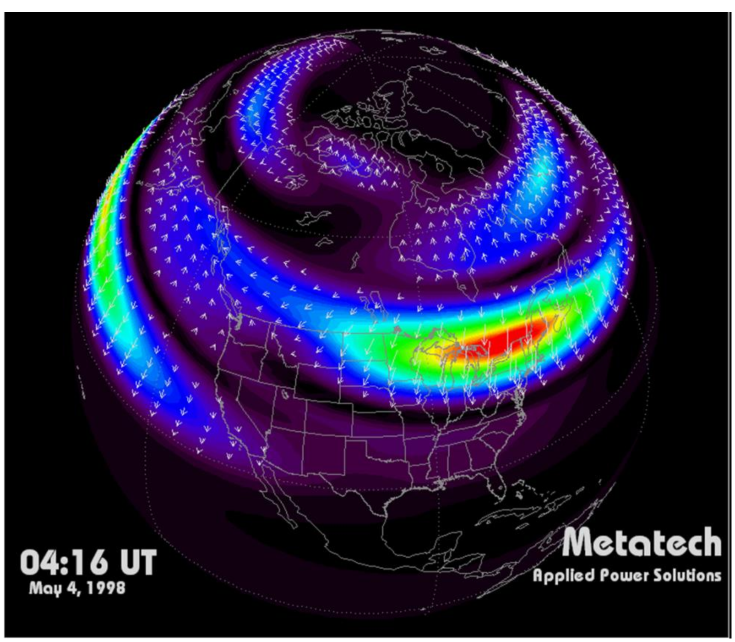


**Figure 2 – Map of Geomagnetic Disturbance conditions at 4:16UT during May 4, 1998 storm. (Source – Meta-R-319)**

The results in Figure 1 provide a comparison between high sample rate measured GIC (~10 second cadence) versus storm simulations that were limited to 1 minute cadence geomagnetic observatory data inputs (B-fields). Due to this limitation of inputs to the model, the model would not be able to reproduce all of the small scale high frequency variations shown in the measured data. However, the simulation does provide very good accuracy and agreement on major spikes in GIC observed, the most important portion of the simulation results that need to be validated. Figure 3 provides a wider view of the impact of the storm in terms of other GIC flow conditions in the Maine and New England region electric power grid, this is provided at time 4:16UT.

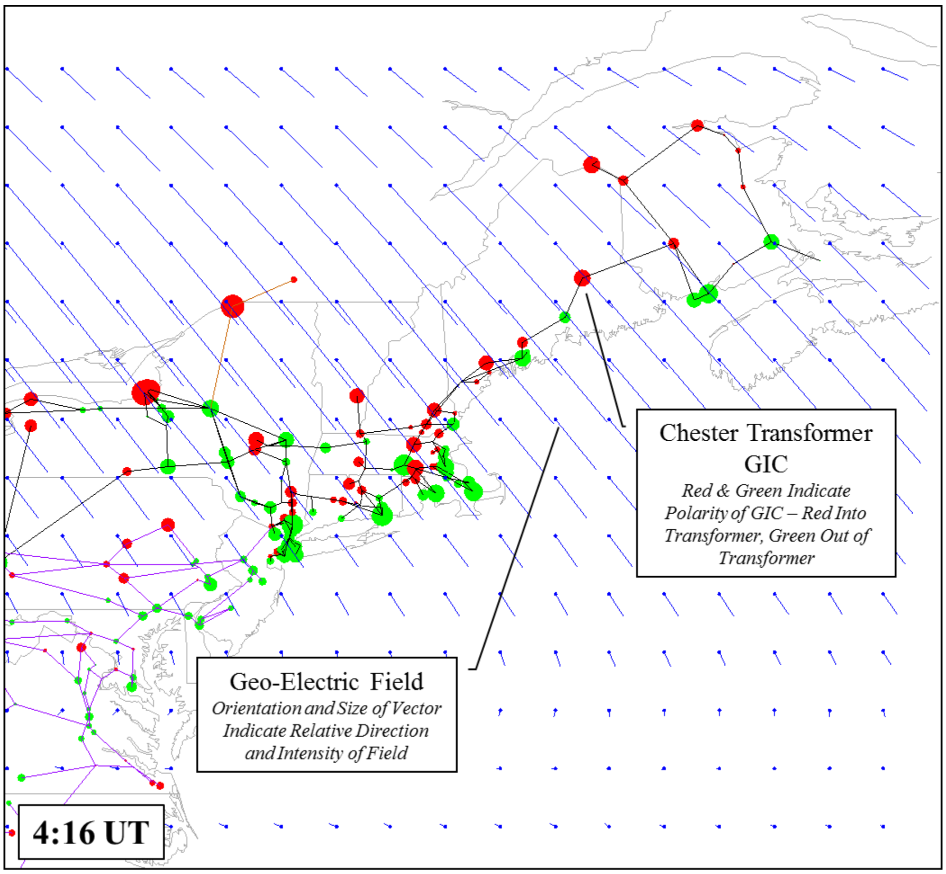


**Figure 3 – GIC flows and disturbance conditions in Maine/New England grid at 4:16UT, May 4, 1998. (Source – Meta-R-319)**

As this illustration shows, the Chester GIC flow is shown along with comparable GIC flows in a number of other locations in the regional power grid at one minute in time. In addition to impacts to the New England grid, extensive power system impacts were also observed to voltage regulation in upstate New York region due to storm. In this map, the intensity and polarity of GIC flows are depicted by red or green balls and their size, the larger the ball the larger the GIC flow and the danger it presents to the transformer and grid. Also shown are the blue vector arrows which are the orientation and intensity of the geo-electric field which couples to the topology of the electric grid and produces the GIC flow patterns that develop in the grid. It is noted that during the period of this storm, the electric fields rotated and all transformers in the grid would experience a variation in the pattern of GIC flows.

Considerable scientific and engineering examination has been performed since the release of the Meta-R-319 report; the report and other subsequent examinations are in close agreement on a number of important parameters of future severe geomagnetic storm threat conditions. For example, it is now well-accepted that severe storm intensity disturbance intensity can reach level of 5000 nT/min at the latitudes of the Maine power grid. NRCan now provides estimates of geo-electric fields for the nearby Ottawa observatory for storms including the May 4, 1998 storm. The ability therefore exists to do cross-validations with this and other proposed NERC ground models and geo-electric field calculation methods.

Observations of GIC at the Chester Maine substation also provide important observational confirmations that allow empirical projection of GIC levels that are plausible at more severe storm intensities. Earlier this year, the Maine electric utilities provided a limited summary of peak GIC observations from their Chester transformer and storm dates to the Maine Legislature. Figure 4 provides a graphical summary that was derived of the peak GIC and peak disturbance intensities (in nT/min) observed at the Ottawa Canada geomagnetic observatory for a number of reported events. The Maine utilities did not provide accurate time stamps (just date only), so that limits some of the ability to accurately correlate disturbance intensity to GIC peaks as the knowledge of timing is extremely coarse. Also since the Ottawa observatory is approximately 550km west of Chester, there is some uncertainty to local storm intensity specifics near Chester. However as shown, there are clear trend lines and uncertainty bounding of the level of GIC and how the GIC increases for increasing storm intensity. This trend line is quite revealing even with all of the previously mentioned uncertainties on the spatial and temporal aspects of the threat environments.

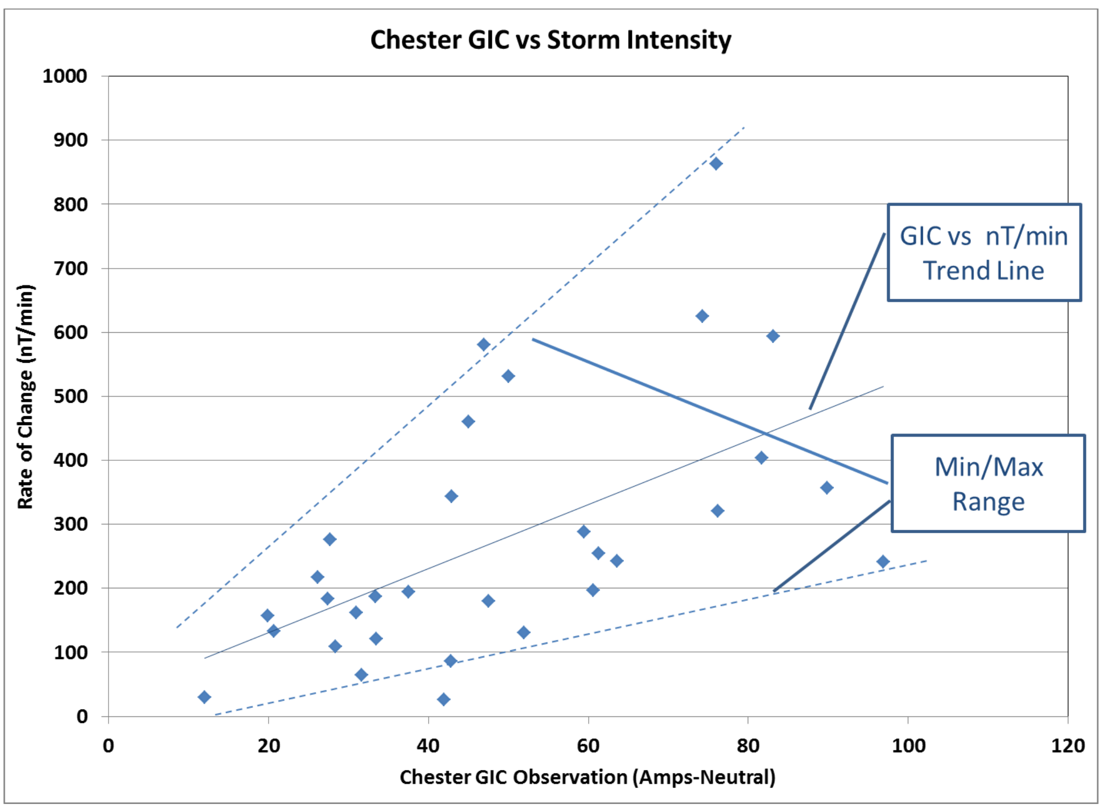


**Figure 4 – GIC versus Storm Intensity (nT/min) from multiple observed GIC storm events at Chester Transformer, in this case the GIC timing is extremely coarse.**

At higher storm intensities, the geo-electric field increases and if only intensity changes (as opposed to spectral content), then the increase in geo-electric field and resulting GIC will be linear. Because storm intensity for very severe storms can reach ~5000 nT/min, this graph can be linearly extended to project the range of GIC flows in the Chester transformer for these more extreme threat conditions. Figure 5 provides a plot similar to that in Figure 4, only with linear extensions of the GIC flow that this observational data estimates.

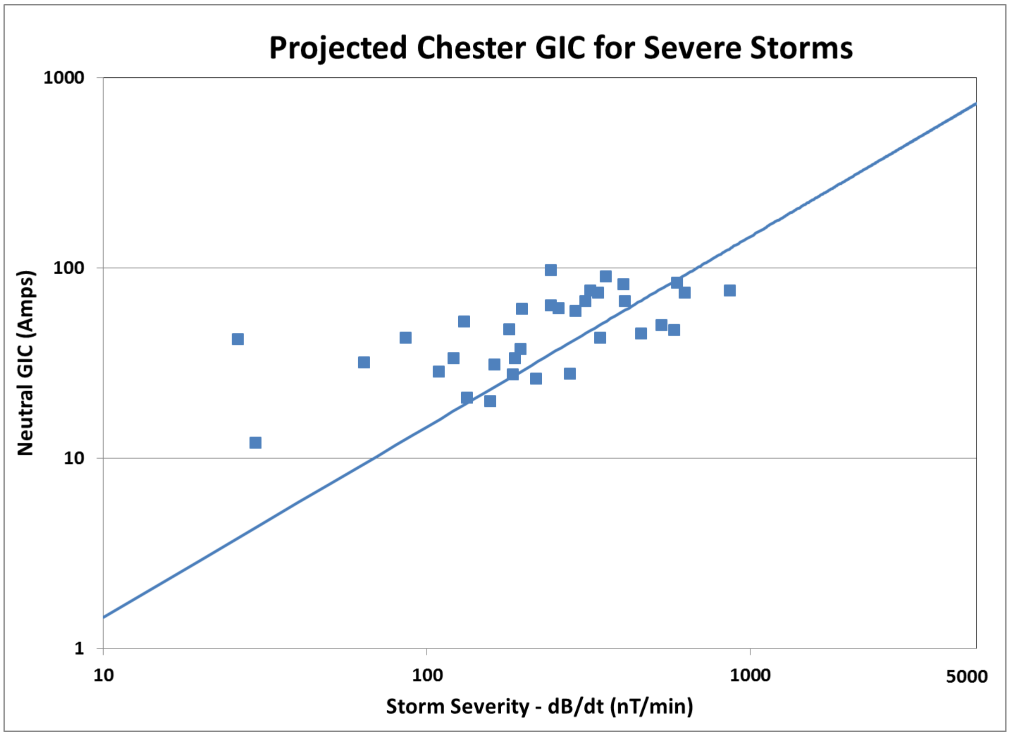


**Figure 5 – Projected Chester GIC flow for storm intensity increasing to ~5000 nT/min.**

Using these data plotting techniques with the previously noted uncertainties, a more detailed examination can be performed for one of the specific storm events which occurred on May 4, 1998. Figure 6 provides again the earlier described GIC plots from Figure 1. Two particularly important peak times are also highlighted on this plot at 4:16UT and 4:39UT where the recorded GIC reaches peaks respectively of -74.3 Amps and -66.6 Amps. These comparisons also show very close agreement with the simulation model results as well. Therefore the peak data points can be more explicitly examined in detail, as a comparison to how GIC vs dB/dt was plotted in Figure 4. In addition to this GIC observation data, there was also dB/dt data observed from a local magnetometer for this storm, which also greatly reduces the uncertainty of the threat environment.

Having all of this data available will aid in utilizing the power system itself as an antenna that can help resolve the geo-electric field intensity that the complex composition of ground strata generates during this storm event. Further once this response is empirically established, this same ground response can be reliably utilized to project to higher storm intensity and therefore higher GIC levels. This provides a blended effort of model and observational data to extract details on how the same grid and ground strata would behave at higher storm intensity levels. One of the advantages that exists in the modeling of the circuits of the transmission networks are that the resistive impedances of transmission lines and transformers (which are the key GIC flow paths) are very well known and have small uncertainty errors. It is also known that the Chester transformer is non-auto, so GIC flow in the neutral also defines the GIC per phase. There is also no doubt about the locations of assets within the circuit topology. Finally, station grounding resistance can also be determined to relatively high certainty as well. In comparison, ground response as has been previously published in the Meta-R-319 report can vary over large ranges, as much as a factor of 6. Therefore direct observations of ground response are highly important and GIC measurements, as will be discussed, provide an excellent proxy or geophysical data that can be used to derive the complex behavior characteristics of the ground strata. This set of understandings can be applied as a tool to significantly bound this major area of uncertainty.

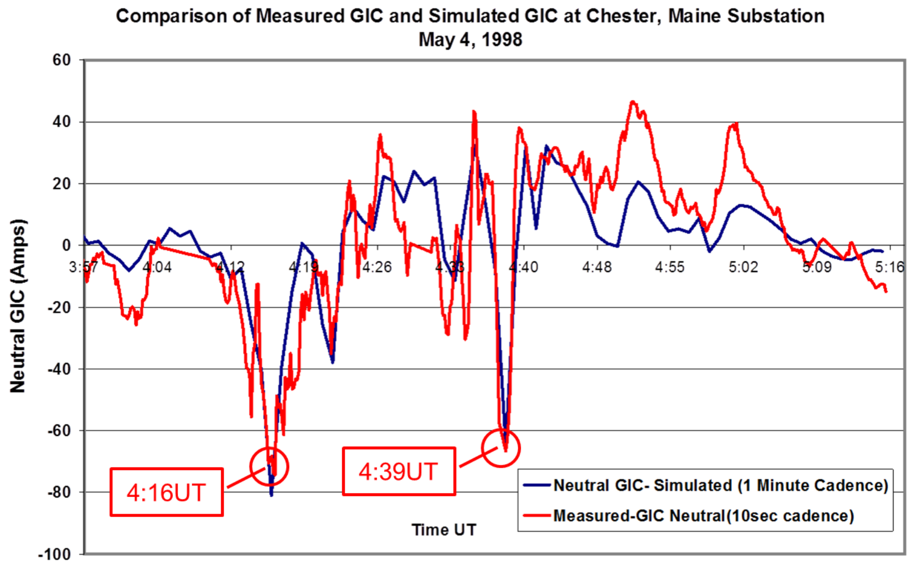


Figure 6 – GIC observation at times 4:16 & 4:39 UT that can be examined in further detail.

### Network Model and Calculation of Chester GIC for 1 V/km Geo-Electric Field

Using the Maine region power grid model of the EHV grid, it is possible to examine what the GIC flow would be at the Chester transformer for a specified geo-electric field intensity of 1 V/km. This specified GIC is an intrinsic and precise characteristic of the network that will provide a useful yardstick to calibrate against for actual GIC flows that occurred and from that a more highly bounded geo-electric field intensity range can be determined at this location. Figure 7 provides a plot of the GIC flow in the Chester transformer for a 1 V/km geo-electric field. Since the topology of the transmission network also greatly determines the resulting GIC, this calculation is performed for a full 360 degree rotation of the orientation of the 1 V/km field.

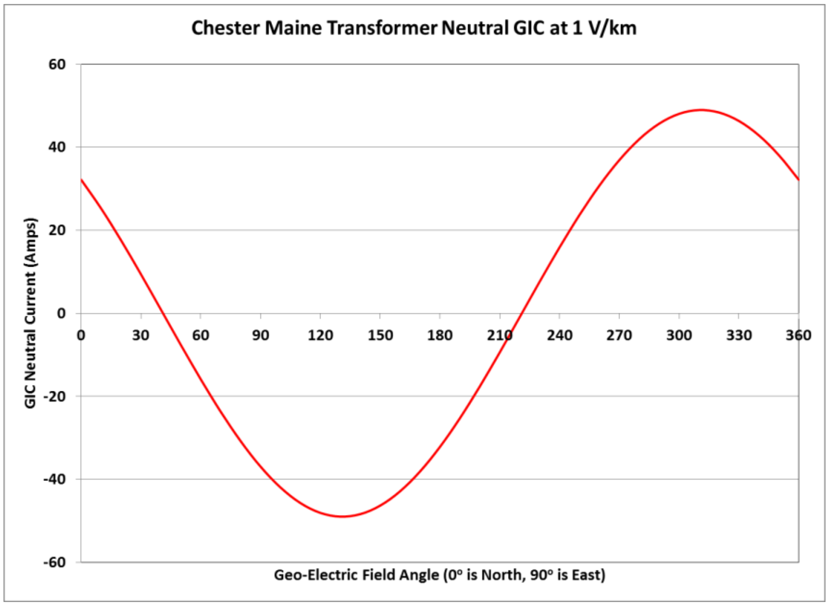


**Figure 7 – GIC flow at Chester transformer neutral for 1 V/km geo-electric field at various orientation angles.**

As the plot in Figure 7 shows, the peak GIC flow at this location is ~49 Amps which occurs at the 130$^{o}$ and 310$^{o}$ angular orientations of the 1 V/km field.

While the GIC to 1 V/km relationship in Figure 7 is developed from a detailed network model, there are also much simpler methods using a limited knowledge of a portion of the local transmission network that can be used to check the accuracy of the model. This involves a simple circuit analysis to derive the resistance and orientation specifics of just the two major transmission lines connecting to Chester. Each of the two 345kV lines connecting to Chester (from Chester-Orrington and from Chester to Keswick New Brunswick) is shown in the map of Figure 8.

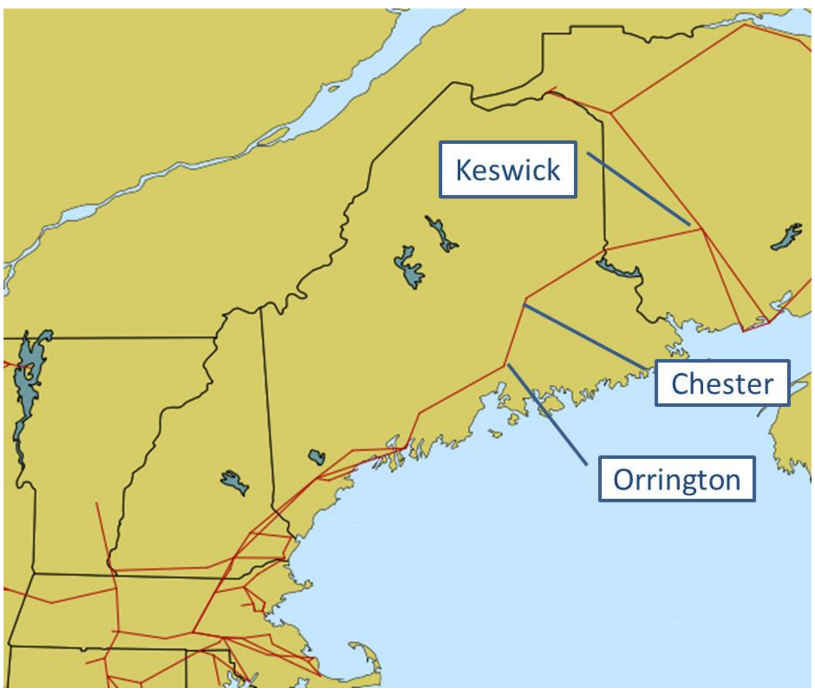


**Figure 8 - Map of Chester Maine and 345kV line interconnections.**

For geomagnetic storms, the orientation of specific transmission lines becomes very important in determining their coupling to the geo-electric field which also has a specific orientation. For example if the orientation of a specific line is identical to the orientation of the geo-electric field, then the GIC will be at a relative maximum. Conversely if the orientations of the field and line are orthogonal, then no coupling or GIC flow will occur. In the case of the Chester to Keswick line, the orientation is at an angle of ~70$^{o}$ (with 0$^{o}$ being North) and for the Chester to Orrington line the angle is ~205$^{o}$. Hence it should be expected that each line will couple differently as the orientation of the geo-electric field changes. Also an important parameter in the calculation of GIC is the line length which also describes the total resistance of this element of the GIC circuit. The point to point distances from Chester are ~80 km to Orrington and ~146 km to Keswick. Figure 9 provides the results of a simple single circuit calculation of the Chester transformer GIC connected to a 345kV transmission line of variable length with a transformer termination at the remote end of that line, the estimated GIC is also shown for the 80 km Orrington line and the 146 km Keswick line using a uniform 1 V/km geo-electric field strength. As shown in this figure, for the two line lengths only a small change in GIC occurs (~11%), even though there is nearly a factor of two difference in line lengths. This calculation assumes a full coupling with the orientation of the geo-electric field, as the geo-electric field changes its orientation to the line with time, and the GIC will change as prescribed via a sine function.

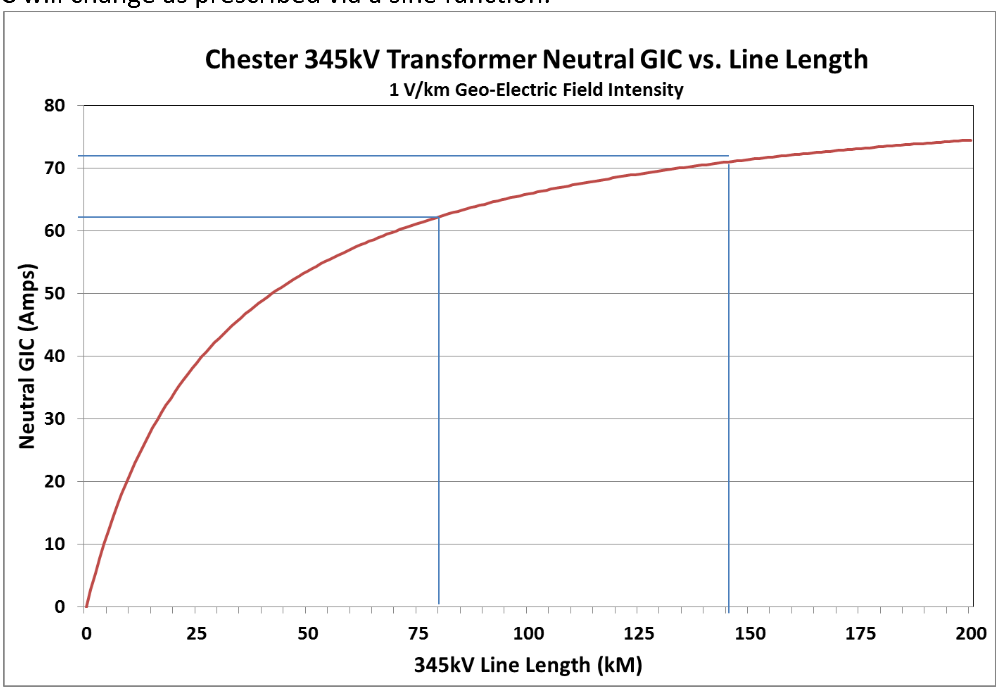


**Figure 9 – Calculated Chester GIC for single circuit 345kV transmission line, 80 km Orrington and 146km Keswick noted**

Given this simple two line case, a discrete calculation can be performed for each line, and using circuit superposition principles(Kirchoff's Laws), the resulting Chester GIC flow can be plotted as well versus the orientation angle of a uniform 1 V/km geo-electric field. This is shown in Figure 10 for each of the two lines and the resultant GIC flow at Chester.

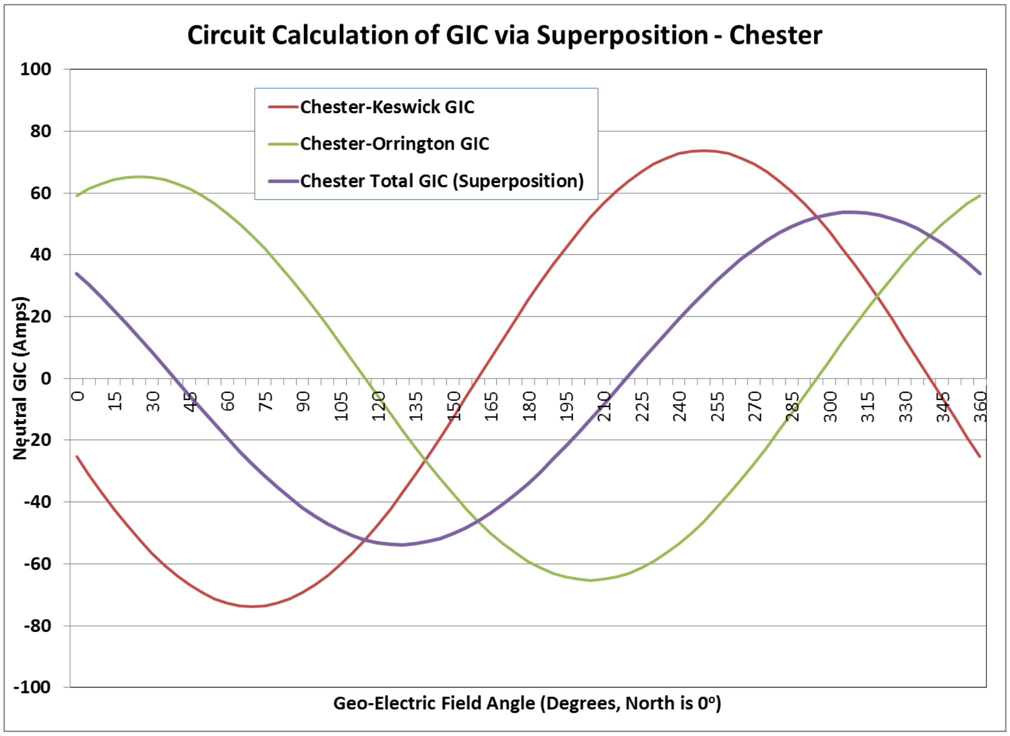


**Figure 10 – GIC flow for each line versus geo-electric field angle and Resultant GIC at Chester.**

## Determining Storm Geo-Electric Field Intensity from Observed GIC

As this Figure 10 illustrates, each line segment will have differing GIC flows versus the orientation of the geo-electric field, and the resultant Chester neutral GIC will also be of lower magnitude and will also have a differing vector angle to each line segment. This simple Ohm's law based circuit calculation can be compared to the more detailed model calculation previously shown in Figure 7, which is shown in Figure 11. As this Figure illustrates, there is very good agreement in GIC flows using the two-line calculation approache (~95% agreement). The detailed model result will be more exact because all of the other network assets are used in the calculation. However, this comparison also shows that the line length parameter dominates the impedance of the circuit and defines the circuit current given the circuit resistances of just a few key components. Knowing both I (or GIC in this case) and R of the circuit allows the ability to precisely determine the driving V or geo-electric field that caused the observed GIC to occur in the transformer.

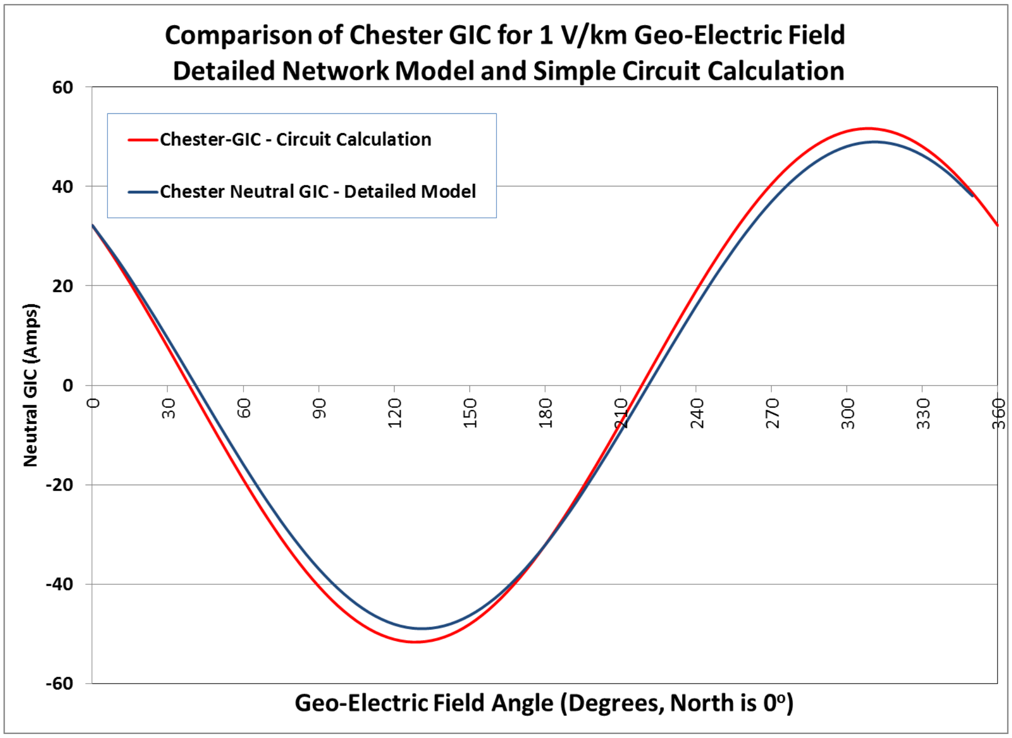


**Figure 11 – Comparison of Calculated Chester GIC from detailed model and simple circuit calculation**

Using the data from Figures 6 (the observed GIC at Chester) and Figure 11, it can be immediately inferred that the peak GIC levels of -66.6 and -74.3 Amps would have required a geo-electric field intensity of greater than 1 V/km to have occurred to produce such high levels of GIC. This is simply a process of utilizing Ohm's law knowledge to begin to develop an improved understanding of the geo-electric field intensity, an otherwise complex and uncertain field to calculate. In contrast it is not possible to infer the upper bound of geo-electric field, in that at angles where GIC nulls occur (such as $40^o$ and $220^o$) even with a very high geo-electric field will not produce a significant GIC flow. As this point illustrates, these estimates can also be greatly improved by adding a simple understanding of geometry to this calculation. For example at time 4:16 UT, the simulation model results shown previously in Figure 3 illustrates a geo-electric field orientation at the Chester location which is almost exactly at $130^o$, the orientation that would produce a peak GIC response at Chester. Using this circuit relationship of current to voltage allows extension to a scaling of the 49 Amp GIC at 1 V/km to a field intensity that would instead result in a 74.3 Amps GIC magnitude. This would lead to the estimated geo-electric field intensity at this 4:16UT time of ~1.5 V/km.

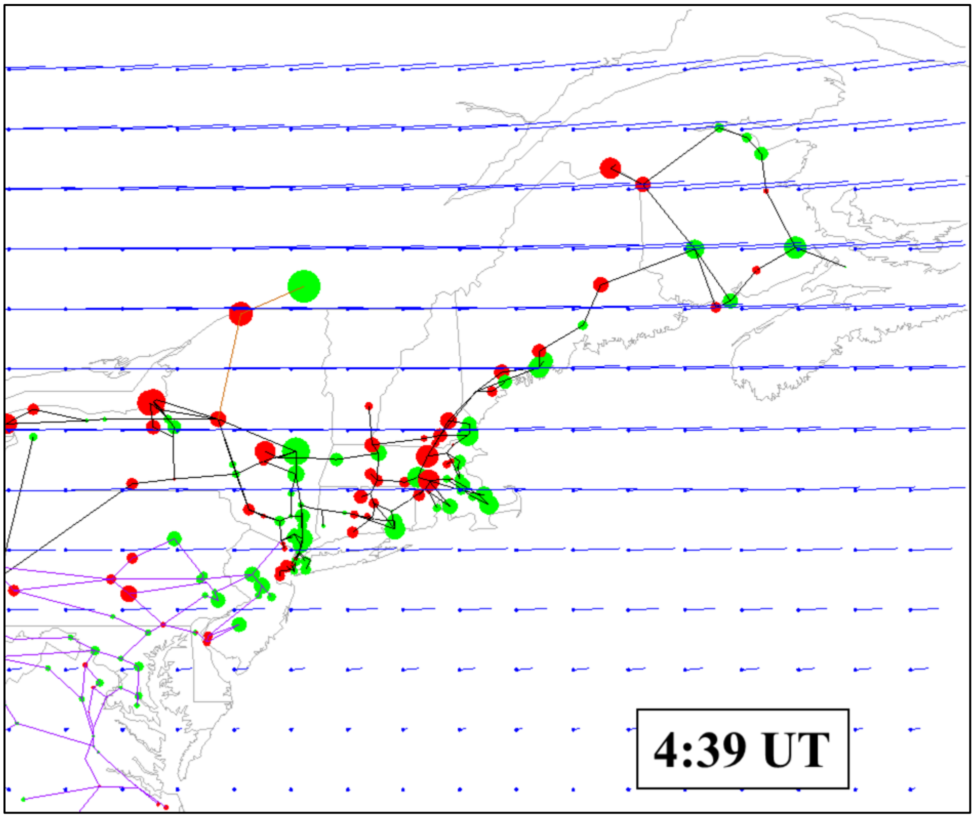


Figure 12 - GIC flows and disturbance conditions in Maine/New England grid at 4:39UT, May 4, 1998.

A similar simplified empirical analysis to confirm model results and expected geo-electric field levels can also be performed at time 4:39UT. Figure 12 provides a simulation output at time 4:39UT which again shows the intensity and geo-electric field angular orientation that would have occurred at this time step. This shows that the field was Eastward oriented or ~90°. Since the characteristic GIC flows at Chester behave as a sine wave for variation of the geo-electric field angle to these circuit assets, a scaling factor based on these angular characteristics can also be applied, which would rerate the field to account for the less-optimal orientation angle at this time. In this case, the 66.6 Amp GIC would be produced by total geo-electric field of ~2 V/km, but only ~1.4 V/km of this total geo-electric field is utilized to produce a GIC flow in the Chester transformer. As this case illustrates, a higher total geo-electric field intensity occurred at 4:39UT than at time 4:16 UT, even though the GIC is lower at 4:39UT. This appears to be counter intuitive. However the event produced a smaller GIC, with the important difference being the angular orientation of the field alone.

As this example illustrates, the observation of GIC when properly placed in context provides an ability to develop an important metric for calculation of the driving geo-electric field that caused the GIC.

**Validating the NERC Geo-Electric Field for Ottawa and New England Ground Models**

As the previous discussion has revealed, the knowledge of GIC flows combined with the network resistance characteristics and locations of network assets can provide all of the information needed to fully resolve the storm Geo-Electric Field Intensity at any particular time during the storm. In other words knowing I and R allows the application of Ohm's law and geometry to derive V or the Geo-Electric Field. This means that GIC measurements can be utilized to derive the geo-electric field at all observation locations and provide important validations of the NERC Ground Models and Geo-Electric Field calculation methodology.

To better understand how GIC can be used to validate the NERC geo-electric field calculations, the regional nature and footprint of each storm needs to be more fully explained. Figure 13 provides a map of the Ottawa and St John's geomagnetic observatories and their proximity to the Chester substation in Maine. As this map illustrates, Chester is positioned in between these two observatories with Ottawa being ~550 km west of Chester and St. Johns being ~1230 km to the east of Chester.

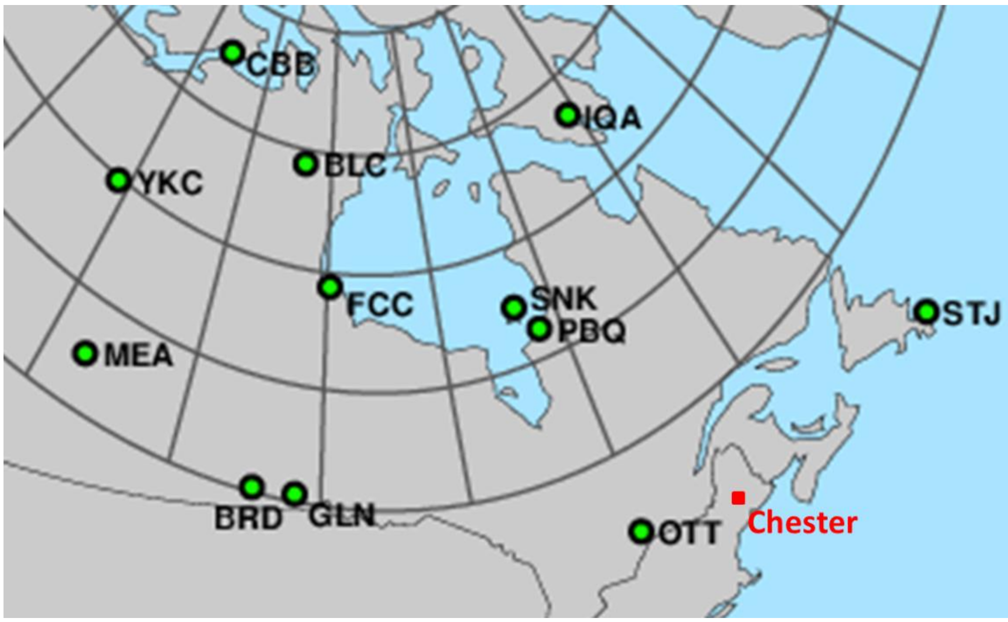


**Figure 13 – Map showing Locations of Chester substation in comparison with Ottawa and St. Johns geomagnetic observatories**

During the time period around 4:39UT which resulted in the peak GIC flow at Chester, both the Ottawa and St. John's geomagnetic observatory also recorded similar impulsive disturbance levels. This plot of these two observatories is shown in Figure 14. Because both of these observatories recorded this same coherent impulsive disturbance, this suggests that the observations had to be connected to the same coherent ionospheric electrojet current structure (in this case an intensification of the Westward Electojet Current) that would have extended all the way between these observatories and directly in proximity to Chester, Maine as well.

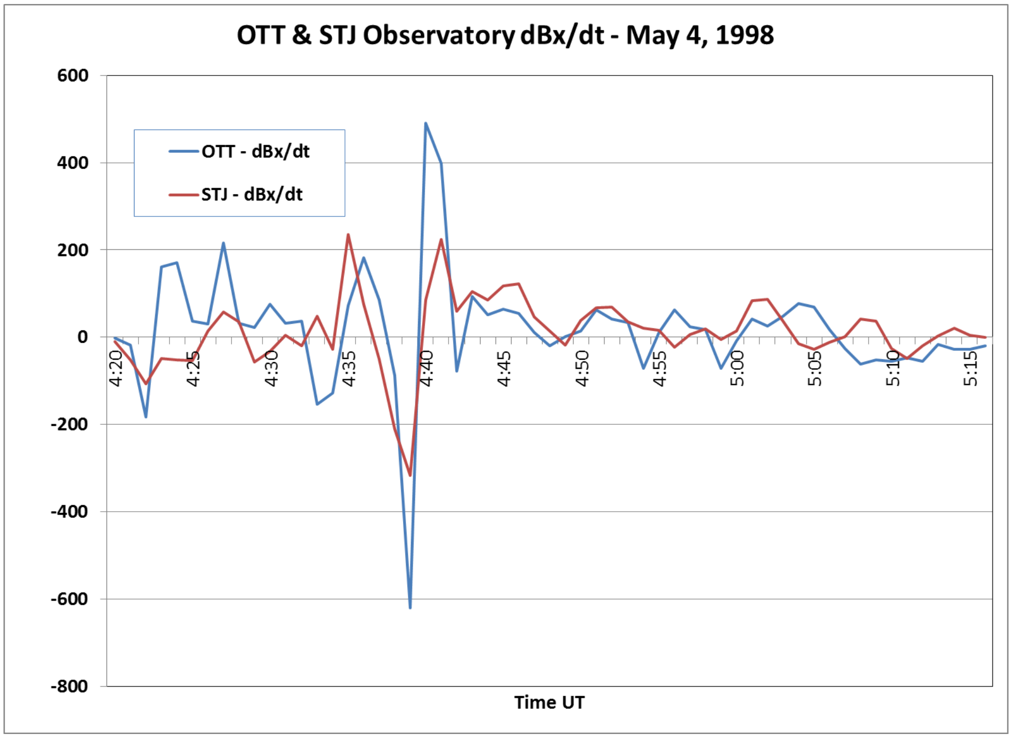


**Figure 14 – Observed Impulsive disturbance at Ottawa and St. John's on May 4, 1998 at time 4:39UT.**

At Chester some limited 10 second cadence magnetometer data was also observed during this storm, and Figure 15 provides a plot of the delta Bx at Ottawa (1 minute data) compared with the Chester delta Bx (10 sec) during the electrojet intensification at time 4:39UT. As this comparison illustrates that at this critical time in the storm, the disturbances at both Ottawa and Chester were nearly identical in intensity.

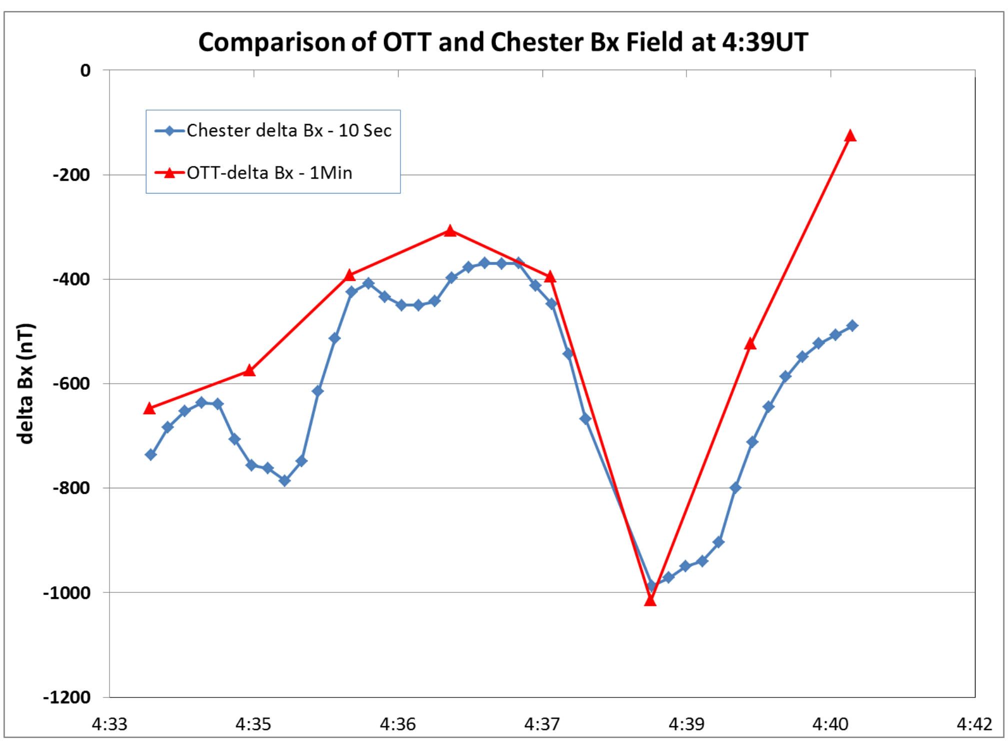


**Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.**

This close agreement between the observations at Ottawa and at Chester therefore allows the comparison of geo-electric field estimates between these two sites to be compared. As we had previously established using Ohm's Law, the peak geo-electric field must reach ~2 V/km to create the level of GIC observed during this storm. Geo-electric field calculations using a simulation model developed by the NERC GMD Task Force can be compared with the simulated geo-electric field in the Metatech simulation[4]. This comparison is shown in Figure 16. In addition, several portions of this geo-electric field waveform comparison are noted.

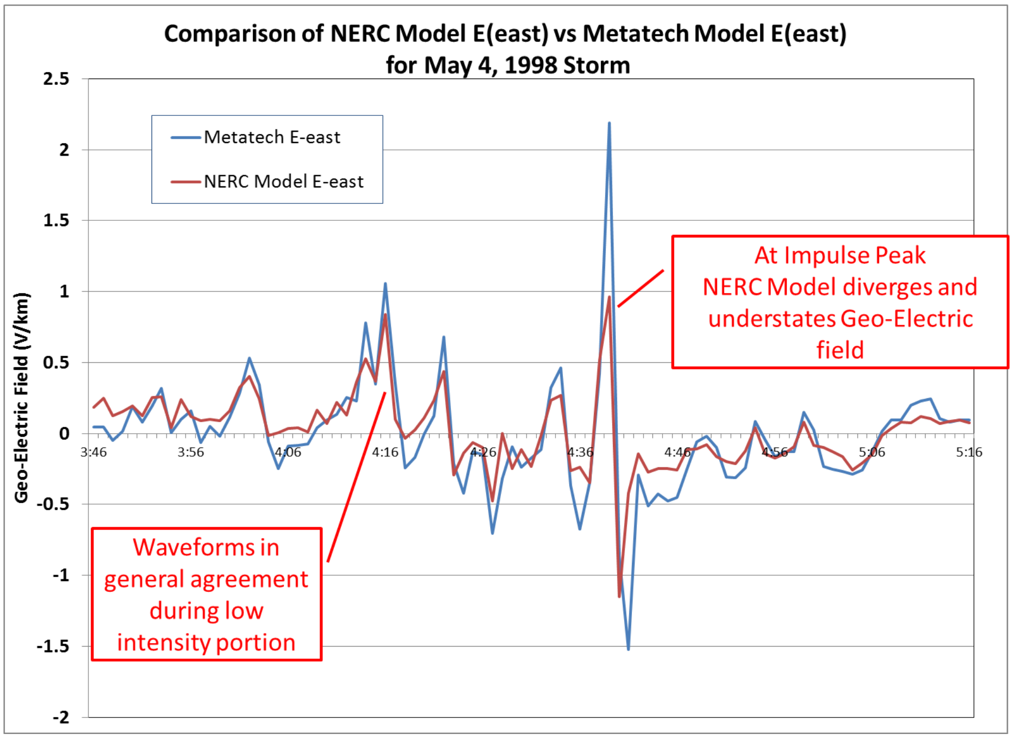


**Figure 16 – Comparison of Metatech east-west geo-electric field calculation and NERC east-west geo-electric field calculation for May 4, 1998 storm event.**

In the earlier portions of the storm simulation, the relative agreement between the two models for the geo-electric field is quite close. This occurs during a quieter and less intense portion of the storm. However as shown at the large impulse around time 4:39 UT, there is a divergence of agreement between the two models with the NERC modeling method understating the Metatech model results by a significant margin. After that impulse is over, the two models again come into relatively close agreement again. This suggests a problem in the NERC model of understating the intensity for more intense impulsive disturbances. As previously shown, the intensity in dB/dt is ~600 nT/min at time 4:39 UT, while it is generally below 100 to 200 nT/min at all other times during the simulation. Hence this higher intensity may be an important inflexion threshold within the NERC model.

As previously discussed Ohm's Law requires a sufficiently large enough geo-electric field to create the GIC flow observed at this location. Using the NERC model geo-electric fields it is possible to calculate the GIC flow and compare this to the GIC flow calculated for the Metatech model and even to the observed GIC. Figure 17 provides a comparison of the NERC model GIC with that computed in the

[4] Geo-elctric field data for this storm downloaded from NRCan http://www.spaceweather.gc.ca/data-donnee/dl/dl-eng.php#view

Metatech model. Figure 18 compares the same NERC Model GIC result with actual GIC observed at Chester. As both of these figures illustrate, the NERC model results will under predict the GIC at the peak storm intensities. In the case of the peak at time 4:39UT the understatement was similar in both the model comparisons and the observed GIC comparison.

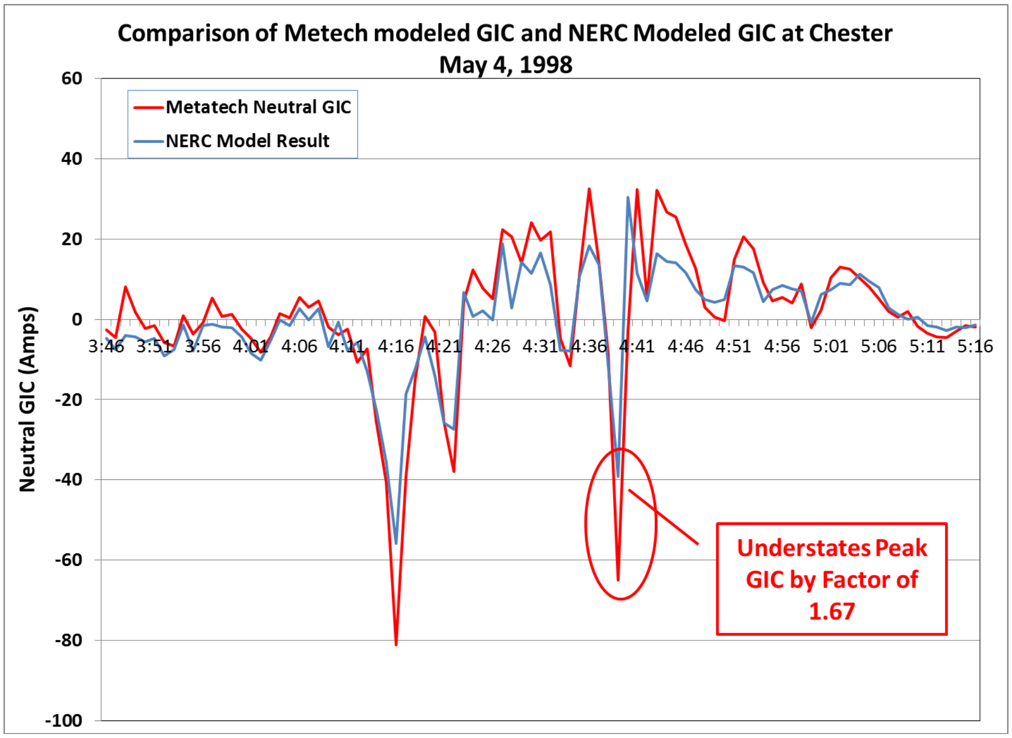


Figure 17 – Comparison of Metatech model GIC to NERC model GIC at Chester.

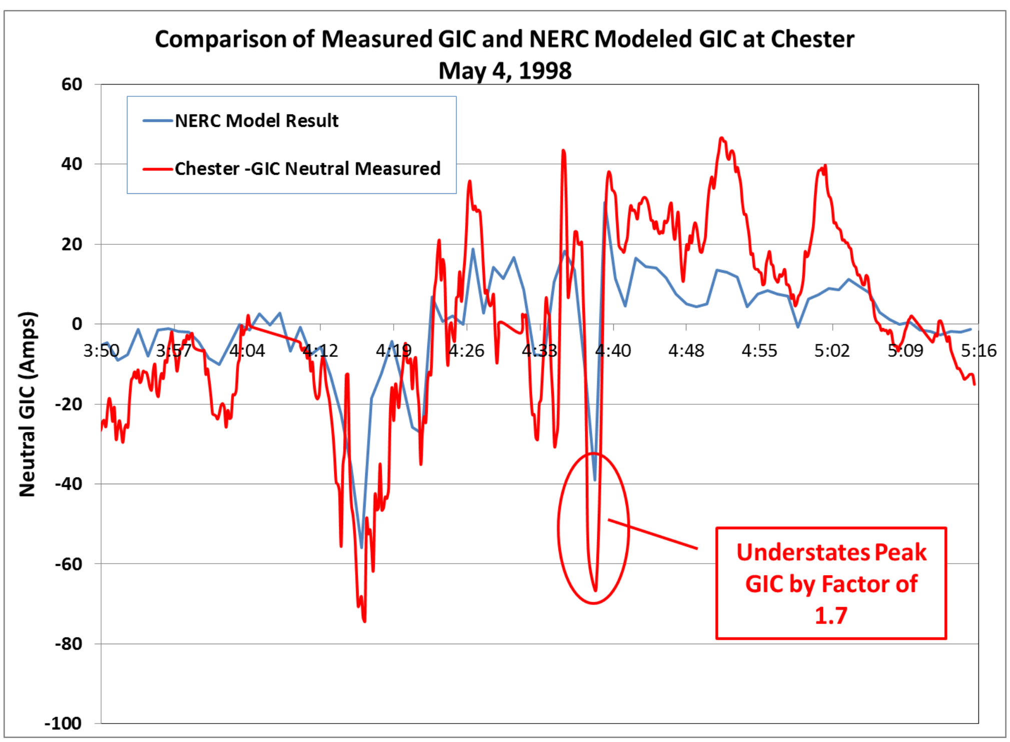


Figure 18 - Comparison of NERC model GIC to observed GIC at Chester.

**NERC Model Validation Problems and Other GIC Observations**

***Seabrook GIC Observations July 13-16, 2012***

While a number of GIC observations have been made over the last few decades in the US, very little of this information has been made publicly available. However where there is public information, it is possible to examine that data in a similar manner to the observations in Chester. Last year, observations as provided in Figure 19 were reported for GIC observations at the Seabrook Nuclear Plant[5]. These observations indicated peak GIC intensities during this storm that reached levels of 30 to 40 amps several times during the storm. The peak of 40 Amps occurred on July 16, 2012.

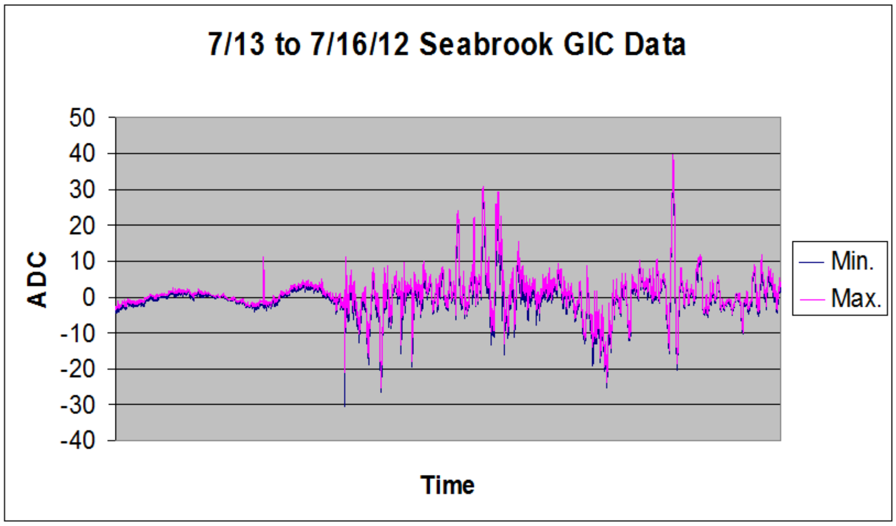


Figure 19 – GIC Observations at Seabrook Nuclear Plant July 13-16, 2012

Seabrook is also located in the New England region and because it is a GSU transformer, the neutral GIC also determines the flow that injects into the 345kV transmission network in that region. Figure 20 provides a map showing the location of Seabrook, and like Chester it will be heavily influenced by the same storm processes that will be observed at the nearby Ottawa observatory. In fact Seabrook is even closer to Ottawa than Chester.

[5] Geomagnetic Disturbance Mitigation for Nuclear Generator Main Power Transformers, Kenneth R. Fleischer, Presented April 16, 20132 at NOAA Space Weather Week Conference, Boulder Co.

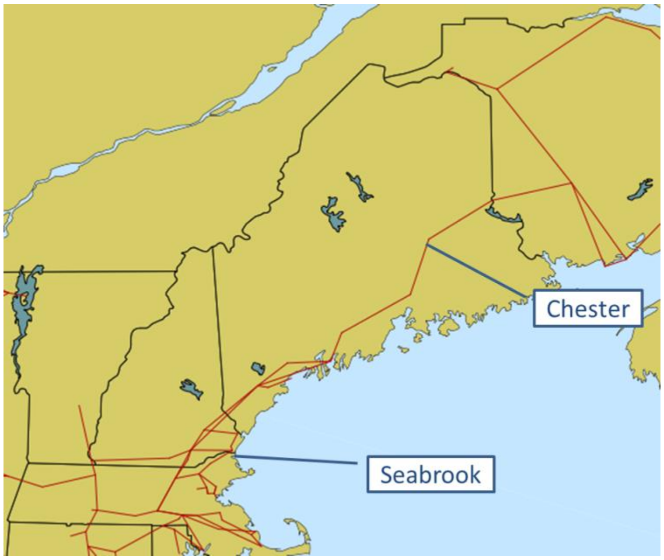


Figure 20 – Location of Seabrook Nuclear Plant in New England region 345kV network.

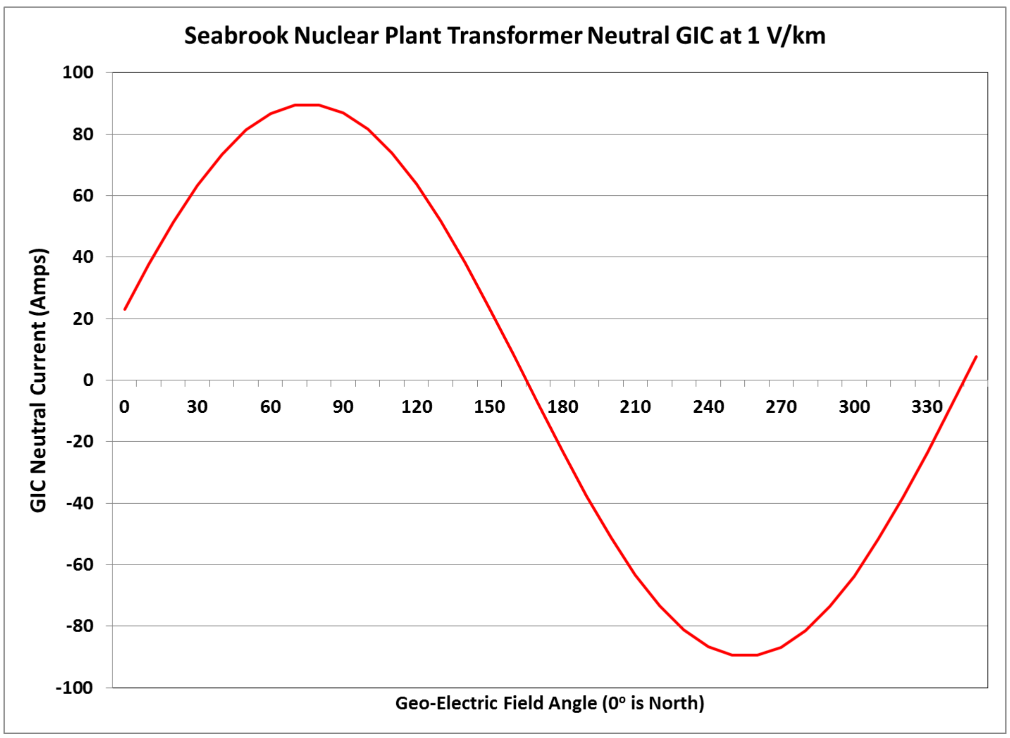


Figure 21 - GIC flow at Seabrook transformer neutral for 1 V/km geo-electric field at various orientation angles.

Figure 21 provides a plot of the characteristic GIC flows that would be observed at Seabrook for a uniform 1 V/km geo-electric field for a 360 degree rotation. This is computed similar to the way it was done at Chester. At this location, a 1 V/km geo-electric field produces ~90 Amp GIC at an 80$^{o}$ angle (essentially nearly east-west oriented). Compared to the characteristic GIC plot for Chester (Figures 7 and 11), for a 1 V/km geo-electric field at Seabrook the GIC will be ~50% higher. This is due to the more integrated connections at Seabrook into the New England 345kV grid and lower circuit impedances, as would be expected. This characteristic indicates that for the 40 Amp GIC observation that occurred on July 16, 2012, there must have been a net east-west geo-electric field of ~0.45 V/km to produce this large of a GIC, a requirement dictated by the Ohm's law behavior of the circuit at Seabrook.

Figure 22 provides a plot of the East-West Geo-Electric Field that would be derived using the NERC model from this storm, using the Ottawa observatory geomagnetic field disturbance conditions as the input. As shown the peak field intensity reaches only ~0.1 V/km which is ~4 times too low to produce the actual GIC observed at Seabrook for this storm event. Hence this storm simulation model provides an example of even worse GIC validation attempt than at Chester. (Not shown is that the peak north-south geo-electric field would have been ~0.12 V/km. But these are also too low and would not couple efficiently with the Seabrook region circuits; therefore this was not a factor in the GIC levels at Seabrook.)

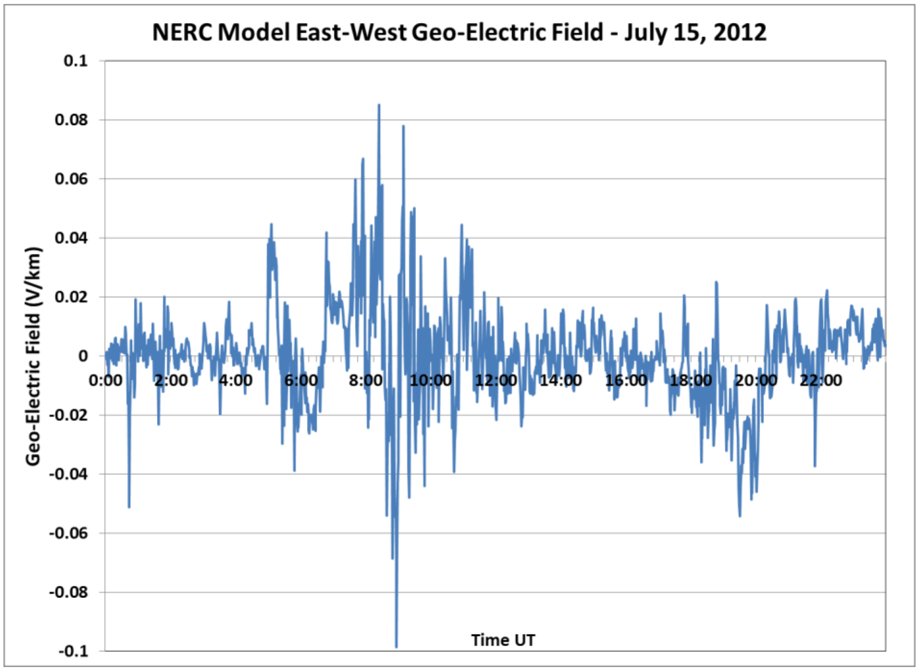

Figure 22 – NERC Model estimated East-West Geo-Electric Field on July 15, 2012 for the NE1 ground model.

### *BPA Tillamook GIC Observations Oct 30, 2003*

In another situation, an examination has been conducted for ground models in the Pacific northwest region of the US. Data on GIC observations in the BPA transmission system have been provided to the Resilient Society Foundation under FOIA provisions and have been provided for analysis and ground model validation purposes. The GIC observations at the BPA Tillamook 230kV substation are examined in this case study. The Tillamook substation is on the western end of the BPA transmission network as shown in the map in Figure 23. There is a single 230kV line from Tillamook to the Carlton substation, but also 3 115kV lines that also connect at Tillamook, two which go in mostly North-South directions and one that connects to the East at Keeler.

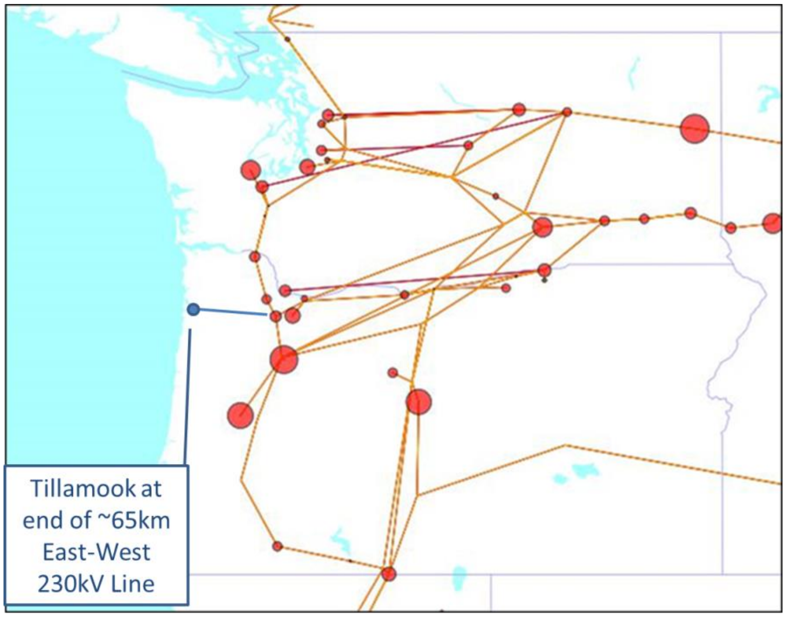


Figure 23 – Map of Tillamook 230kV substation and BPA 500kV network

Figure 24 provides a set of observations of GIC over a 2 hour time period at Tillamook which BPA provided in both 5 minute average and 2 second cadences during the October 30, 2003 storm. As shown in the 2 sec cadence data, the peak GIC approached nearly 50 Amps around time 19:55UT.

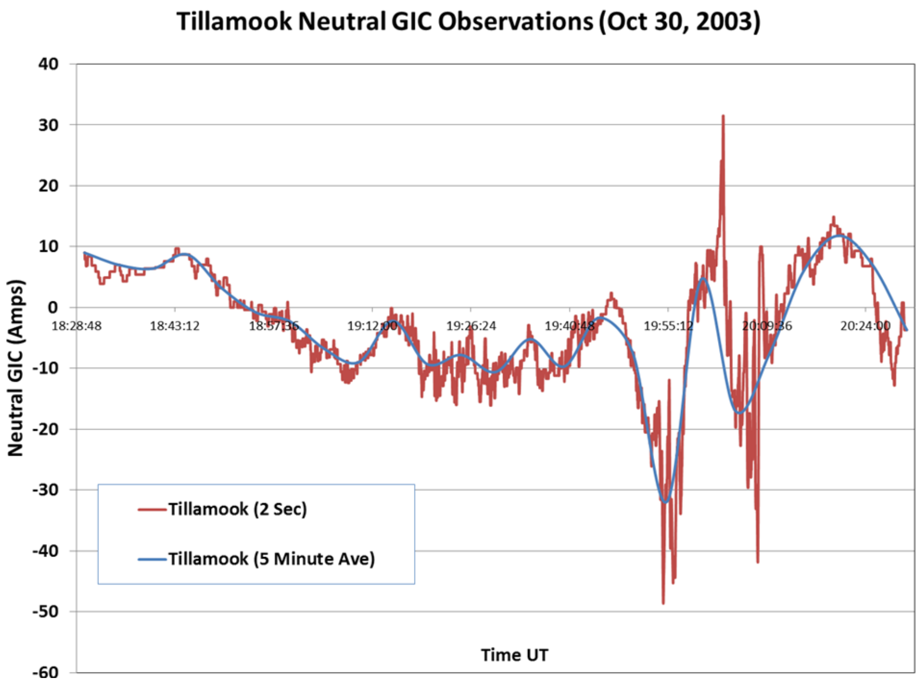


Figure 24 – Tillamook Neutral GIC observations on Oct 30, 2003, both 2 second and 5 minute average levels are shown

The Oct 30, 2003 storm conditions around time 19:55 UT are summarized from regional geomagnetic observatories as shown in Figure 25. This summary indicates that a region of intensification did encroach down into the Tillamook proximity at this time and would have been responsible for the peak GIC flows observed at this time, though Tillamook was not exposed to the worst case storm intensities.

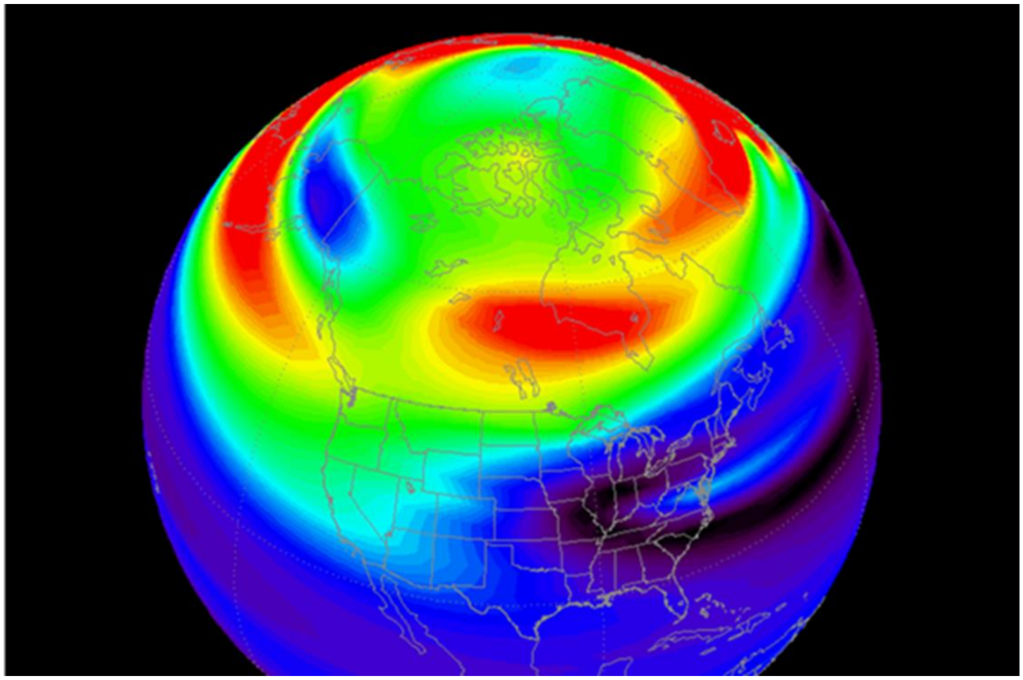

Figure 25 – Regional storm conditions at time 19:55UT October 30, 2003 at time of peak Tillamook GIC flows

Using methods similar to those developed for the Chester station and the various BPA physical data sources available, the characteristic GIC flows for the Tillamook 230kV autotransformer can be calculated for a rotated 1 V/km geo-electric field. The results for this are shown in Figure 26 and the peak GIC reaches a level of ~38 Amps for a predominantly east-west oriented geo-electric field. Therefore when examining the GIC levels observed at Tillamook on Oct 30, 2003, Ohm's law would constrain that the minimum geo-electric field in this region would need to exceed 1 V/km (in at least the east-west direction) to produce the nearly 50 Amps GIC peaks.

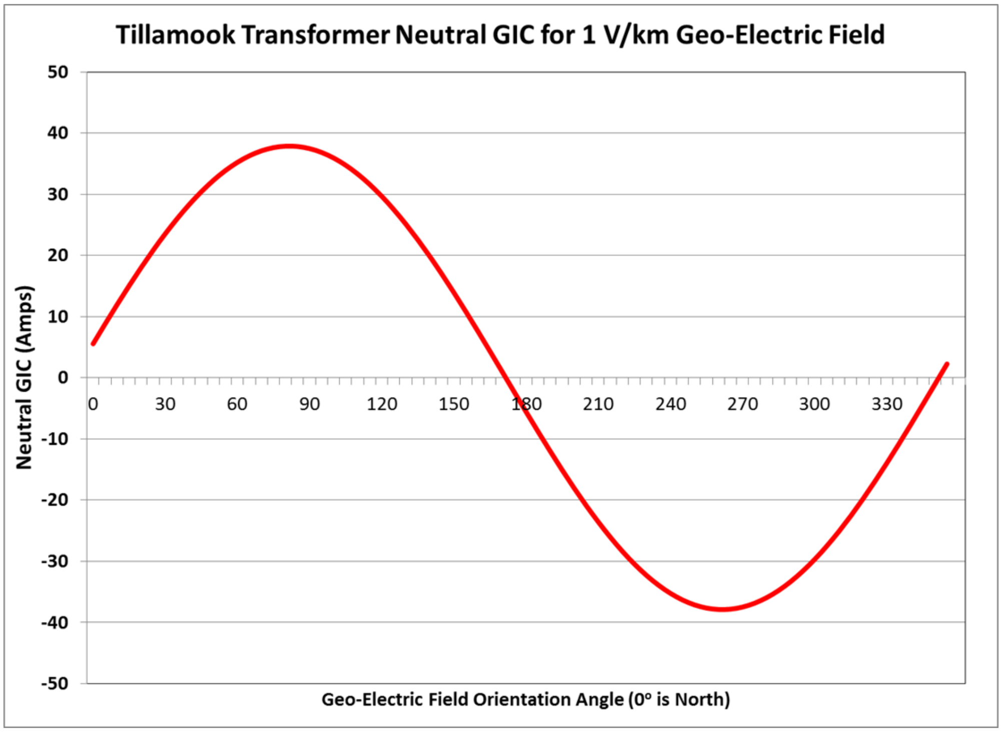

Figure 26 - GIC flow at Tillamook transformer neutral for 1 V/km geo-electric field at various orientation angles.

The NERC model calculations for East-West geo-electric field using the PB1 model are shown in Figure 27 for the same time interval as shown in Figure 24 for the Tillamook high GIC observations, but since the Tillamook GIC flow characteristics are defined in Figure 26, it is possible to utilize this to derive the minimum East-West geo-electric field responsible for producing the GIC flows in Figure 24. These results are also presented in Figure 27 with the NERC model predictions for this storm.

As Figure 27 shows, the peak geo-electric field as strictly constrained by Ohm's law must exceed 1 V/km during portions of the GIC flow where the Tillamook GIC exceeded ~38 amps level. At all times, the NERC model geo-electric field did not exceed even 0.25 V/km. As this comparison illustrates, the NERC model greatly understates the peak geo-electric field intensities at the peak GIC flow portions of the storm. In some cases this understatement is more than a factor of 4 to 5 times too small. This degree of divergence is also worse than what was observed at Chester Maine and is similar to the error level noted for Seabrook.

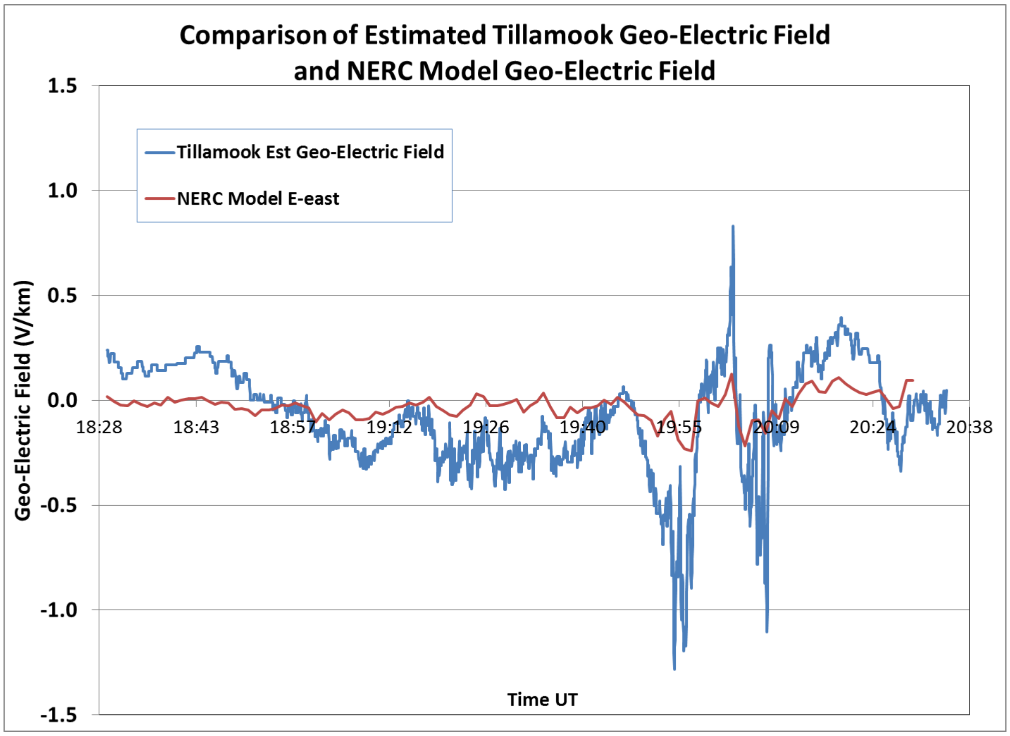


**Figure 27 – Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the Oct 30, 2003 storm**

There are other storms available with similar levels of GIC measurements observed at the Tillamook substation and 230kV line. Because this 230kV line is an East-West orientated line, GIC observed there will be largely driven by North-South variations (or dBx/dt) in the geo-magnetic field which subsequently produces an East-West geo-electric field. Figure 28 provides a plot of the nearest geomagnetic observatory (Victoria, ~340 km north of Tillamook) and the Tillamook GIC observed during an important storm on July 15-16, 2000. These geomagnetic disturbance conditions reach a peak of just over 150 nT/min resulting in GIC flows (5 min averaging) reaching -43.5 Amps at time 20:25UT. Figure 29 provides a detailed regional summary which show the more global storm conditions that were occurring at time 20:25UT over North America. As this Figure illustrates, the most severe storm conditions were located quite far to the North, so the GIC observed for these conditions could have been driven to much higher levels had the intensity extended further southward.

From the GIC observations for this storm, the minimal Geo-Electric field levels necessary to produce the GIC flows observed at Tillamook can be again calculated. This can also again be compared with the estimates used by NERC in modeling this storm event, this comparison is shown in Figure 30. In the comparison of the NERC model geo-electric field with the actual geo-electric field as derived from GIC measurements, the NERC model again greatly under predicts peak V/km intensities, by as much as a factor of ~5 or more at peak intensities times. These results are similar to the results from the Oct 30, 2003 storm as shown in Figure 27 and further confirm that the NERC models will not accurately depict storm conditions.

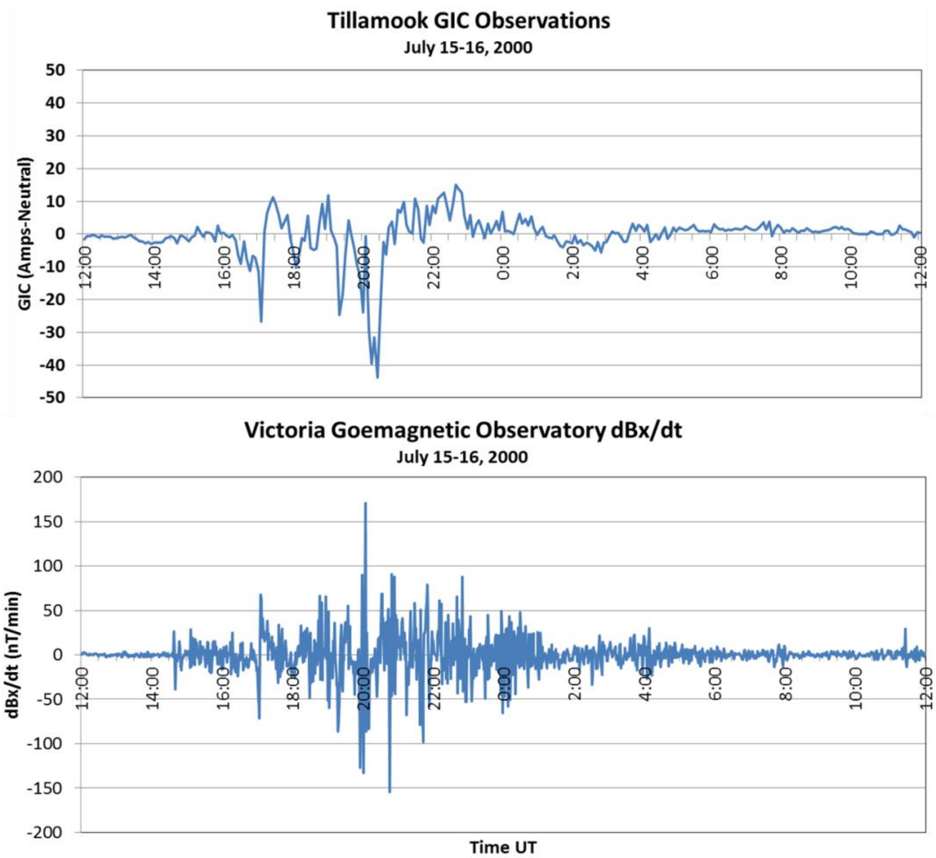


**Figure 28 – Observed Tillamook GIC and Victoria dBx/dt for storm on July 15-16, 2000.**

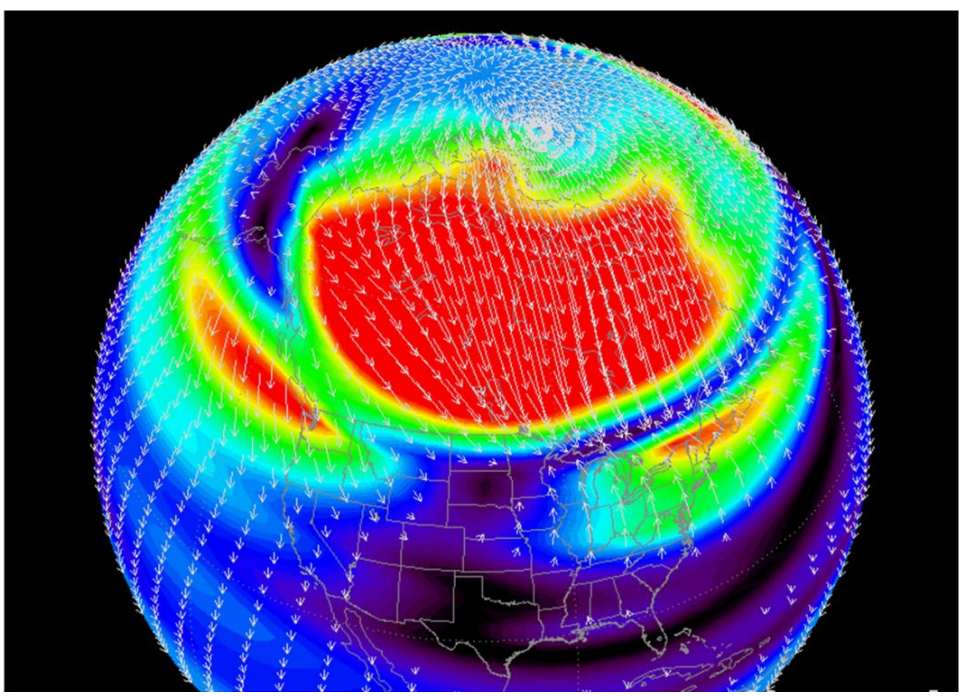

**Figure 29 - July 15, 2000 at time 20:25UT storm conditions at time of Tillamook -43.5 Amp GIC Peak.**

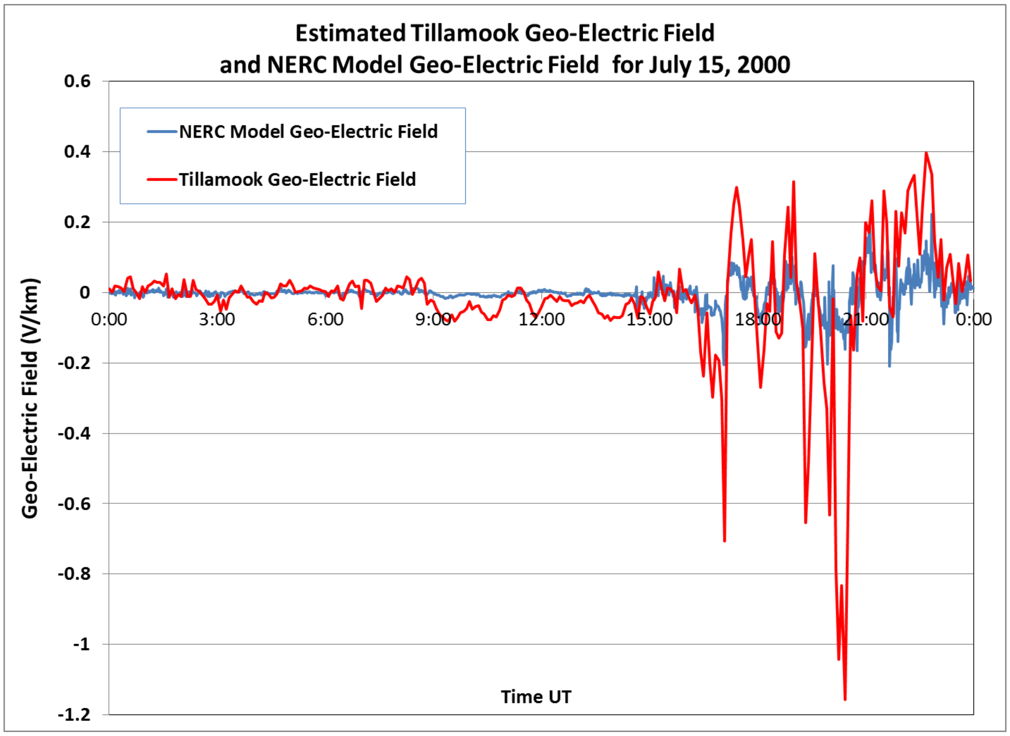


**Figure 30 - Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the July 15, 2000 storm**

### Other Instances of Geo-Electric Field Modeling Concerns

The NERC geo-electric field simulation tools had their genesis out of the Finnish Meteorology Institute and have since been adopted at NASA (A. Pulkkinen) and also at Natural Resources Canada and many other locations around the world. Pulkkinen in particular was a key NERC GMD Task Force science investigator, a key EPRI science investigator along with staff from NRCan. Pulkkinen was also a member of the NERC GMD Standards Task Force, where the draft standards incorporating these tool sets are fully integrated into the science analysis and are recommended tools for system analysis. In the entirety of the NERC GMD task force investigations, no evidence has been made available by the NERC GMD Task Force of rigorous validations of the suite of ground models and derived relationships that have been published. USGS scientist involved in the effort asked for more power industry efforts to do model validations at several NERC GMD meetings, with no active participants and no subsequent publications supporting the ability to verify these models.

These FMI/NRCan-based geo-electric field modeling approaches use a Fourier transform method[6]. Fourier transforms are well-conditioned for periodic signals, not the very aperiodic events associated with abrupt, high intensity impulsive disturbances typical for severe geomagnetic storms. Therefore a Fourier approach needs to be carefully considered and tested rigorously to assure fidelity in output resolution for severe impulsive geomagnetic field disturbances. An additional geo-electric field modeling approach has been developed by Luis Marti based upon Recursive Convolution[7]. Unfortunately no independent validation for this model was noted in their IEEE paper on the model, rather it was only

[6] How to Calculate Electric Fields to Determine Geomagnetically-Induced Currents. EPRI, Palo Alto, CA: 2013. 3002002149.

[7] Calculation of Induced Electric Field During a Geomagnetic Storm Using Recursive Convolution, Luis Marti, A. Rezaei-Zare, and D. Boteler, IEEE TRANSACTIONS ON POWER DELIVERY, VOL. 29, NO. 2, APRIL 2014

tuned to agree with the FMI/NRCan geo-electric field model output results. In addition, staff from the NOAA SWPC and USGS were also provided tool sets that were tuned to the NASA-CCMC/NRCan geo-electric field models so that the results that each examined would be the same. Hence no real independent assessments were ever apparently undertaken by all of these organizations. Therefore all of the various NERC GMD models appear to produce results that will consistently understate the true geo-electric field intensity.

In looking at recent publications by Pulkkinen, et. al., a paper titled "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden"[8] was published in the Space Weather Journal in 2008. In this paper the authors presented results from several storm events that were similar in intensity to the May 4, 1998 storm that was discussed in a prior section of this report. Figure 31 is a set of plots from Figure 7 of their paper showing the disturbance intensity (dB/dt in nT/min) in the bottom plot and the measured and calculated GIC in the top plot. As illustrated in this Figure, the storm intensity is similar to that experienced in Maine during the May 4, 1998 storm at ~500 nT/min. In regards to the comparison of the Measured and Calculated GIC the simulation model greatly under predicts the actual measured GIC during the most intense portion of the storm around hour 23 UT by substantial margins (factor of 3 or more). This is the same symptomatic outcome observed in the NERC model results and provides another independent assessment with possible inherent problems with this modeling approach.

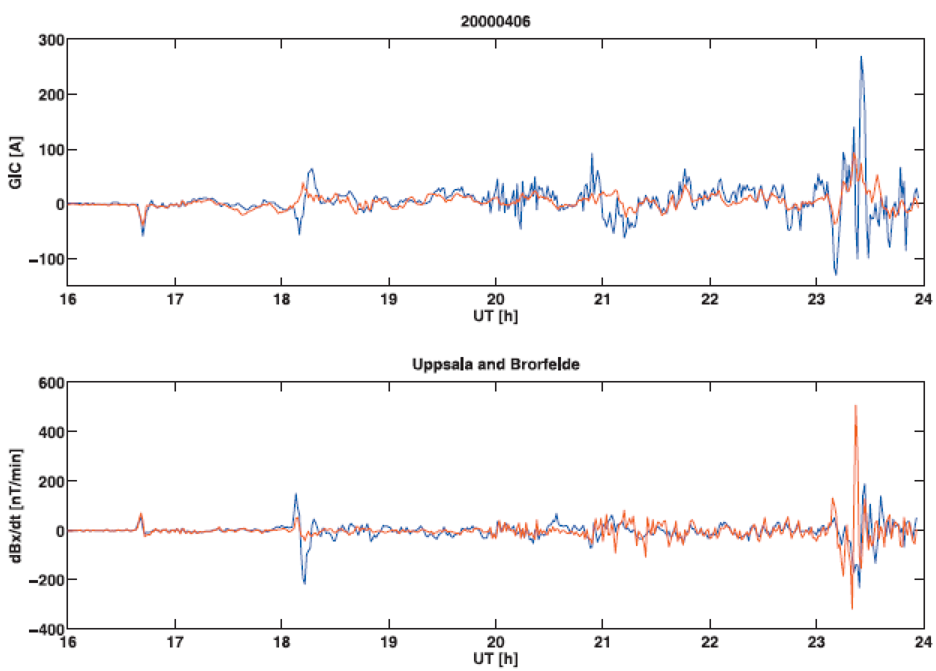


Figure 7. The top curve shows the measured (blue) and calculated (red) GIC at Simpevarp-2 (6 April 2000). The bottom curve shows $dB_x/dt$ from Uppsala (blue) and Brorfelde (red).

**Figure 31 – Plot Figure 7 from Pulkkinen, et.al.,paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing storm intensity and GIC comparisons**

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[8] Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden, M. Wik, A. Viljanen, R. Pirjola, A. Pulkkinen, P. Wintoft, and H. Lundstedt, SPACE WEATHER, VOL. 6, S07005, doi:10.1029/2007SW000343, 2008

In another example from this same paper, a figure shown below as Figure 32 provides a comparison plot of the Measured and Calculated GIC during the July 15, 2000 storm at the same transformer in southern Sweden. The GIC results as in all prior comparisons greatly diverge during the occurrence of the largest and most sudden impulsive disturbance events, such as those between 21 and 22 UT.

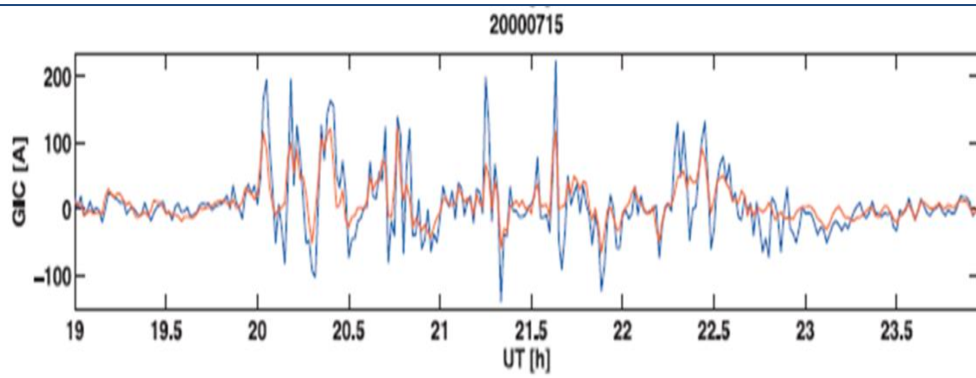


Figure 4. Measured (blue) and calculated (red) GIC at Simpevarp-2 for three events in 1998 to 2000.

**Figure 32 - Plot Figure 4 from Pulkkinen, et.al.,Paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing GIC comparisons**

**Conclusions – Draft NERC Standards are Not Accurate and Greatly Understate Risks**

As these examples illustrate the results of calculations of geo-electric fields by the NERC models and any subsequent NERC predicted GIC's appear to exhibit the same problems of significantly under predicting for intense storm disturbances. In all locations that were examined the results of the models consistently under predicted what Ohm's Law establishes as the actual geo-electric field. This is a systemic problem that is likely related to inherent modeling deficiencies, and exists in all models in the NERC GMD Task Force and likely in many other locations around the world.

This has significant implications for nearly all of the findings of the NERC GMD Task Force. These erroneous modeling approaches were utilized to examine the peak geo-electric field outputs to much higher disturbance intensities for severe storms. For example the underlying analysis performed by NERC Standard Task Force members Pulkkinen and Bernabeu[9] for the 100 Year storm peaks utilized the faulty geo-electric field calculation model to derive the peak geo-electric fields for the reference Quebec ground models. This would drastically understate the peak intensity of the storm events by the same factor of 2 to 5 ratios as noted in the prior case study analysis. Therefore the standard proposing the NERC Reference Field level of between 3 to 8 V/km would be an enormous under-estimation and result in an enormous miss-calculation of risks to society. The same modelling errors are part of all earlier Pulkkinen/Pirjola[10] derived science assessments which also examined these peaks and 100 year storm statistics. As all prior validations within this report have established, the NERC geo-electric field model under predicts geo-electric field by a factor of 2 to 5 for the most important portions of storm events. Hence these errors have been entirely baked into the NERC GMD Task Force cake and their draft standards as well. Therefore the entirety of the Draft Standard does not provide accurate assessments

[9] 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.

[10] Pulkkinen, A., R. Pirjola, and A. Viljanen, Statistics of extreme geomagnetically induced current events, Space Weather, 6, S07001, doi:10.1029/2008SW000388, 2008.

of the geo-electric field environments that will actually occur across the US. It has also been shown in this White Paper that undertaking a more rigorous development of validated geo-electric field standards can be done in a simple and efficient manner and that such data to drive these more rigorous findings already exists in many portions of the US. Efforts on the part of NERC's standard team and the industry to withhold this material information are counter-productive to the overarching requirements to assure public safety against severe geomagnetic storm events. Such fundamental and significant flaws in technical calculations and procedural actions should not be a part of any proposed standard and a redraft must be undertaken.