# Consideration of Comments

## Project 2013-03 Geomagnetic Disturbance Monitoring

The Project 2013-03 Drafting Team thanks all commenters who submitted comments on the revised draft stage 1 Standard (EOP-010-1). Project 2013-03 will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by geomagnetic disturbances (GMD) in two stages as directed by the Federal Energy Regulatory Commission (FERC or the Commission)in Order No.  779 (*Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013)(Order No. 779):

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

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

The standard was posted for a 45-day formal comment period from September 4, 2013 through October 21, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form.  There were 37 sets of responses, including comments from approximately 120 individuals from approximately 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

**Summary Consideration:**

The drafting team has reviewed all comments and made the following non-substantive changes to incorporate stakeholder recommendations:

- Section 5 (Background): Capitalized "Protection System" because it is defined in the NERC Glossary of Terms.

- Requirement R1: Revised the requirement to include the term Operating Process in R1 and R1 part 1.2 and changed language to be consistent with Requirement R3. The revised requirement with highlighted changes is as follows:

**R1**. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

**1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

**1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within ~~the~~ its Reliability Coordinator Area.

- **Measure M1**: Inserted the word "current" to conform to NERC guidelines for writing Measures to support this type of Requirement. The revised measure with highlighted change is as follows:

**M1**. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

- **Requirement R2**: Clarified that the Reliability Coordinator shall disseminate forecasted and current space weather information *to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan*. The revised requirement with highlighted change is as follows:

**R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients ~~as specified~~ in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

- **Requirement R3**: Inserted the word GMD, so that the phrase "GMD Operating Procedure or Operating Process" would be consistent with Requirement R1. The revised requirement is as follows:

**R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating

Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

- **Implementation Plan.** A clarifying change was made to the Implementation Plan to conform to the effective date language in the standard, which was changed in the prior draft in response to concerns raised by Canadian entities.

A summary response to each comment 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.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

## Index to Questions, Comments, and Responses

**The Industry Segments are:**

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

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Group | Frank Gaffney | Florida Municipal Power Agency | X | | X | X | X | X | | | | |

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

| Group/Individual | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2. | Group | Guy Zito | Northeast Power Coordinating Council | | | | | | | | | | X |

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

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

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Michael Crowley | Dominion | SERC | 1, 3, 5, 6 |
| 2. Mike Garton | Dominion | NPCC | 5, 6 |
| 3. Louis Slade | Dominion | RFC | 5, 6 |
| 4. Randi Heise | Dominion | MRO | 5, 6 |

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

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

| Group/Individual | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 5. Group | Sammy Roberts | SERC OC Review Group | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. James Case | Entergy | SERC | 1, 3, 6 |
| 2. William Berry | OMU | SERC | 3 |
| 3. Gerald Beckerle | Ameren | SERC | 1, 3 |
| 4. Gary Kobet | TVA | SERC | 1, 3, 5, 6 |
| 5. Michael Lowman | Duke Energy | SERC | 1, 3, 5, 6 |
| 6. Terry Bilke | MISO | SERC | 2 |
| 7. Phil D'Antonio | PJM Interconnection | SERC | 2 |
| 8. Patrick McGovern | Georgia Transmission Corporation | SERC | 1 |
| 9. Marsha Morgan | Southern Company | SERC | 1, 5 |

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 10. Tom Pruitt | Duke Energy | SERC | 1, 3, 5, 6 | | | | | | | | | |
| 6. Group | Robert Rhodes | SPP Standards Review Group | | X | | | | | | | | |
| **Additional Member** | **Additional Organization** | **Region** | **Segment Selection** | | | | | | | | | |
| 1. Kevin Frick | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 2. Louis Guidry | Cleco Power LLC | SPP | 1, 3, 5 | | | | | | | | | |
| 3. Michael Herzog | Omaha Public Power District | MRO | 1, 3, 5 | | | | | | | | | |
| 4. Stephanie Johnson | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 5. Bo Jones | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 6. Richard Kalina | Omaha Public Power District | MRO | 1, 3, 5 | | | | | | | | | |
| 7. Dong-Hyeon Kim | Burns & McDonnell | NA - Not Applicable | NA | | | | | | | | | |
| 8. Allen Klassen | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 9. Jeff Knottek | City Utilities of Springfield | SPP | 1, 4 | | | | | | | | | |
| 10. Tiffany Lake | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 11. Greg McAuley | Oklahoma Gas & Electric | SPP | 1, 3, 5 | | | | | | | | | |
| 12. James Nail | City of Independence, MO | SPP | 3 | | | | | | | | | |
| 13. Mahmood Safi | Omaha Public Power District | MRO | 1, 3, 5 | | | | | | | | | |
| 14. Bryan Taggart | Westar Energy | SPP | 1, 3, 5, 6 | | | | | | | | | |
| 15. Scott Williams | City Utilities of Springfield | SPP | 1, 4 | | | | | | | | | |
| 7. Group | Colby Bellville | Duke Energy | X | | X | | X | X | | | | |
| **Additional Member** | **Additional Organization** | **Region** | **Segment Selection** | | | | | | | | | |
| 1. Doug Hils | Duke Energy | RFC | 1 | | | | | | | | | |
| 2. Lee Schuster | Duke Energy | FRCC | 3 | | | | | | | | | |
| 3. Dale Goodwine | Duke Energy | SERC | 5 | | | | | | | | | |
| 4. Greg Cecil | Duke Energy | RFC | 6 | | | | | | | | | |
| 8. Group | Greg Campoli | ISO/RTO Council Standards Review Committee | | X | | | | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Kathleen Goodman | ISO-NE | NPCC | 2 |
| 2. Charles Yeung | SPP | SPP | 2 |
| 3. Ali Miremadi | CAISO | WECC | 2 |
| 4. Terry Bilke | MISO | MRO | 2 |
| 5. Al DiCaprio | PJM | RFC | 2 |
| 6. Cheryl Moseley | ERCOT | ERCOT | 2 |
| 7. Ben Li | IESO | NPCC | 2 |

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| 9. | Group | Don Hargrove | Oklahoma Gas & Electric | X | | X | | X | X | | | | |

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

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| 10. | Group | Ben Engelby | ACES Standards Collaborators | | | | | | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Bill Hutchison | Southern Illinois Power Cooperative | SERC | 1 |
| 2. John Shaver | Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc. | WECC | 1, 4, 5 |
| 3. Shari Heino | Brazos Electric Power Cooperative, Inc. | ERCOT | 1, 5 |
| 4. Scott Brame | North Carolina Electric Membership Corporation | RFC | 1, 3, 4, 5 |
| 5. Megan Wagner | Sunflower Electric Power Corporation | SPP | 1 |

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| 11. | Group | Jamison Dye | Bonneville Power Administration | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. Dan Goodrich | Technical Operations | WECC | 1 |
| 2. Ran Xu | Technical Operations | WECC | 1 |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 12. | Individual | Janet Smith | Arizona Public Service Co. | X | | X | | X | X | | | | |
| 13. | Individual | Ryan Millard | PacifiCorp | | | | | X | X | | | | |
| 14. | Individual | Kaleb Brimhall | Colorado Springs Utilities | X | | X | | X | X | | | | |
| 15. | Individual | Wayne Johnson | Southern Company | X | | X | | X | X | | | | |
| 16. | Individual | Erika Doot | US Bureau of Reclamation | X | | | | X | | | | | |
| 17. | Individual | William R. Harris | Foundation for Resilient Societies | | | | | | | | X | | |
| 18. | Individual | Nazra Gladu | Manitoba Hydro | X | | X | | X | X | | | | |
| 19. | Individual | Ayesha Sabouba | Hydro One | | | X | | | | | | | |
| 20. | Individual | Thomas Foltz | American Electric Power | X | | X | | X | X | | | | |
| 21. | Individual | Anthony Jablonski | ReliabilityFirst | | | | | | | | | | X |
| 22. | Individual | Kenn Backholm | Public Utility District No.1 of Snohomish County | X | | X | X | X | X | | | X | |
| 23. | Individual | John Seelke | Public Service Enterprise Group | X | | X | | X | X | | | | |
| 24. | Individual | Russ Schneider | Flathead Electric Cooperative, Inc. | | | X | X | | | | | | |
| 25. | Individual | Bret Galbraith | Seminole Electric Cooperative, Inc. | X | | X | X | X | X | | | | |
| 26. | Individual | Phil Anderson | Idaho Power | X | | | | | | | | | |
| 27. | Individual | RoLynda Shumpert | South Carolina Electric and Gas | X | | X | | X | X | | | | |
| 28. | Individual | Michael Falvo | Independent Electricity System Operator | | X | | | | | | | | |
| 29. | Individual | Kathleen Goodman | ISO New England Inc. | | X | | | | | | | | |
| 30. | Individual | Richard Vine | California ISO | | X | | | | | | | | |
| 31. | Individual | Alice Ireland | Xcel Energy | X | | X | | X | X | | | | |
| 32. | Individual | Don Schmit | Nebraska Public Power District | X | | X | | X | | | | | |
| 33. | Individual | Cheryl Moseley | Electric Reliability of Texas, Inc. | | X | | | | | | | | |
| 34. | Individual | Sergio Banuelos | Tri-State Generation and Transmission Association, Inc. | X | | X | | X | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 35. | Individual | Jen Fiegel | Oncor Electric Delivery Company LLC | X | | | | | | | | | |
| 36. | Individual | Rich Salgo | NV Energy | X | | X | | X | | | | | |
| 37. | Individual | Robert B Stevens | CPS Energy | | | | | X | | | | | |

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

| Organization | Supporting Comments of “Entity Name” |
|---|---|
| ISO New England Inc. | IRC SRC |
| Colorado Springs Utilities | NA |
| Southern Company | SERC OC |
| Associated Electric Cooperative, Inc. - JRO00088 | SERC OC Review Group |
| South Carolina Electric and Gas | SERC Operating Committee (OC) |
| California ISO | The ISO supports the comments submitted by the ISO/RTO Standards Review Committee |

1. **The drafting team has revised EOP-010-1 in response to stakeholder comments. Changes include removing the BA from applicability, clarifying applicability for TOPs, adding a Requirement for RCs to disseminate space weather information, removal of administrative requirements that do not benefit reliability, and clarifying changes to the language of requirements and measures. Do you agree that the revised standard correctly addresses the Stage 1 directives of Order No. 779 and is acceptable? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

**Summary Consideration:** The drafting team thanks all who commented on the revised EOP-010-1. All comments have been reviewed and changes that the drafting team considers appropriate were incorporated into a subsequent revision. A summary of comments and the drafting team's response is provided:

- **Consistent language between Requirement R1 and Requirement R3 in describing the required operating measures as "Operating Procedures or Operating Processes." Commenters recommended that Requirement R1 and Requirement R1 part 1.2 include language that matches Requirement R3.** The drafting team has made this clarifying change in the final revision.
- **Unclear or implied requirements for the Reliability Coordinator to include space weather information in the GMD Operating Plan. Some commenters stated that the requirement was unclear; some recommended that the requirement specifically state what information should be disseminated or what recipients it should be disseminated to. Some commenters did not believe the requirement was necessary.** The drafting team's intent with Requirement R2 is to maintain the Reliability Coordinator's existing obligation to disseminate space weather information as specified in IR0-005-3.1a Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. To clarify this intent, the final version of EOP-010-1 Requirement R2 states that the Reliability Coordinator will disseminate space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. The drafting team believes Requirement R1 and Requirement R2 provide the Reliability Coordinator with appropriate flexibility to tailor its GMD Operating Plan to promote consistent awareness of space weather information in the Reliability Coordinator Area.
- **Requirements for the RC to coordinate GMD Operating Procedures and Operating Processes. Commenters stated that R1 needed to be more specific about how coordination should occur. Some commenters stated that Requirement R1 should be expanded to specifically address recourse when the RC required changes to a TOPs Operating Procedures or Operating Processes after review.** The drafting team believes that Requirement R1 as written describes the essential elements to assure coordination and is consistent with the roles described in the NERC Functional Model. The drafting team did not believe that the suggestion to replace "coordinate" with "affirm the compatibility of" in Requirement R1 improved clarity. C*oordination* is intended to ensure that Operating Procedures within a Reliability Coordinator Area are not in conflict with one another; it is *not* intended to be a review by the Reliability Coordinator of the technical aspects of the GMD Operating Procedures or Operating Processes. The Transmission Operator is responsible for the technical aspects of its Operating Procedures or Operating

Processes pursuant to Requirement R3. For example, if Company A submitted an Operating Procedure proposing to take Line X out of service at specified GMD conditions and Company B submitted an Operating Procedure that relies on Line X remaining in service in the event of a GMD -- it is the responsibility of the Reliability Coordinator to *identify* this conflict. The Reliability Coordinator would then require Company A and Company B to resolve this conflict and resubmit their Operating Procedures. The drafting team believes that the coordination and resolution of identified operating conflicts can be resolved using existing agreements and processes.

- **Applicability to all networks greater than 200 kV with grounded-wye transformers. Some commenters indicated that 300 kV threshold is the appropriate voltage threshold based on the Oak Ridge National Labs report or other unspecified utility research. Another commenter stated that the 200 kV minimum voltage threshold was imprudent because a large population of transformers would not be covered or protected by the operating procedures, and that an unacceptable opportunity for GIC to enter the transmission network was permitted. One commenter recommended alternate wording in the applicability section. One commenter reiterated earlier comments that the applicability should be limited to single-phase transformers.** The drafting team believes the applicability section is worded clearly and would not be improved with the suggested wording. The drafting team agrees that single-phase transformers are more susceptible to half-cycle saturation due to GIC than three-phase three-limb core units, but does not agree that core construction is appropriate for use in determining applicability. Reactive power absorption in three-phase three-limb core units could have system impacts in some networks.

  The effect of GIC in networks less than 200 kV has negligible impact on the reliability of the interconnected transmission system. Using a voltage threshold higher than 200 kV could potentially create a reliability gap in many systems by excluding from the reliability standard a portion of the network that can be affected by GMD. Establishing 200 kV as the lower-bound threshold is consistent with operating experience and modeling guidance provided in the peer-reviewed technical literature. The drafting team's technical justification for establishing a 200 kV threshold in the applicability of EOP-010-1 is posted to the project page. (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx ).
- **Applicable functional entities.**
  - **Balancing Authority. A commenter stated that Balancing Authorities needed to be included as an applicable functional entity in order for the RC to effectively coordinate Operating Procedures.** The SDT agrees that Balancing Authorities have a role in GMD response, as with many other reliability risks. This role is adequately covered by the real-time responsibilities described in the NERC Functional Model and as required by other Reliability Standards.
  - **Generator Operator. Some commenters stated that Generator Operators should be included in the standard.** The SDT agrees that Generator Operators have a role in GMD response as with many other reliability risks. This role is adequately covered by the real-time responsibilities described in the NERC Functional Model and as required by other Reliability Standards. Generator Operators may be included in stage 2 standards.

- **Transmission Operator. One commenter indicated that the standard should apply to the RC only.** The functional model states that the Transmission Operator has responsibility and authority for the reliable operation of the transmission system within the Transmission Operator Area. Applicability of EOP-010-1 to the Transmission Operator is consistent with this responsibility and authority.
- **Time horizons. Some commenters recommended changes to time horizons, or additions to the rationale box to clarify the drafting team's intent.** When requirements include performance elements that take place over different time horizons, it is acceptable to include more than one time horizon. The drafting team clarifies that development of the GMD Operating Plans, Processes, or Procedures occurs in the Long-Term Planning Time Horizon, which is defined as a planning horizon of one year or longer. Maintenance of the GMD Operating Plans, Processes, or Procedures occurs in the Operations Planning Time Horizon. Implementation of GMD Operating Plans, Processes, or Procedures occurs in the Operations Planning, Same-Day and Real-Time Time Horizons depending on the activity. The drafting team did not agree with a comment that suggested removal of the Long-term Planning Time Horizon from Requirements R1 and R3. The drafting team agrees that this type of planning could occur in the Operations Planning time horizon, but because space weather follows an 11-year solar cycle it could also be viewed by an entity from a long-term planning perspective.
- **Alternate approaches using existing standards. Some commenters stated that existing standards already manage GMD impacts.** Order No. 779 directs NERC to develop new reliability standards or modify existing requirements to mitigate the risk of GMD. The SDT chose to develop new reliability standards as the most efficient means of providing improved reliability during GMD events, although the team has recognized that existing standards are related to EOP-010-1, as noted herein.
- **Additions to Requirements or new Requirements. A small number of commenters suggested substantive changes and the drafting team does not believe there is consensus support for substantive changes. For example, one commenter suggested that EOP-010-1 should be developed regionally, rather than as a continent-wide standard.** The drafting team believes that the approach in the standard is appropriate to ensure a common level of preparedness for GMD events continent-wide, while at the same time allowing flexibility for each entity to tailor its procedures and plans to account for regional and local considerations.

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| CPS Energy | No | I beleive this standard should be developed regionally, not at a national level. |
| Flathead Electric Cooperative, Inc. | No | I believe that either this standard should only apply to the RC or the stage 1 directives should be addressed outside the standards process. Recent GDM events have shown little to no impact on the Bulk Electric System and creating a GDM Operating Plan |

| Organization | Yes or No | Question 1 Comment |
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| | | requirement and auditing process is likely to have little reliability impact other than blindly following the letter of these directives. |
| Foundation for Resilient Societies | No | Question 1:Our Foundation's Case Study on Maine and ISO New England's capacity to mitigate a severe solar geomagnetic storm (March 2013 - found on website www.resilientsocieties.org) reaffirmed our prior understanding that the Regional Coordinators (in this case ISO-New England) cannot adequately coordinate "operating procedures" to mitigate a severe GMD event without concurrent jurisdiction over Balancing Authorities (BAs) and Generator Operators (GOs). In a severe solar storm, the combination of generation reserves together with demand response reserves may not enable Regional Coordinators (RCs) to balance loads without active preparation and support of balancing authorities. For ISO-New England that would include Canadian resources and balancing operators beyond the authority and scope of FERC Order No. 779. In effect, the various balancing (BAL) standards do not include standards for emergency hydroelectric generation or protection of equipment, such as series capacitors and static VAR compensators (SVC), necessary to maintain voltage stability for power imported from Canada. Without power imported from Balancing Authorities outside of ISO-New England, which also may be at risk of concurrent Geomagnetically-Induced Current (GIC), reactive power consumption, and adverse harmonics, the New England region is more likely to be at risk of prolonged electric grid blackout. The rationale of NERC's drafting team for excluding Balancing Authorities from participation as responsible entities to fulfill "operating procedures" is stated in NERC's "Functional Entity Applicability" document, which states:"... Balancing Authorities (BA) should not be among the applicable functional elements because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events."To the contrary, as GIC equipment monitors are already deployed within some Balancing Authorities, BA's need to assess the performance and GMD-related deterioration of networks during the moderate solar geomagnetic storms in coming years. Balancing Authorities may benefit from modeling balancing options under degraded conditions, such as the loss of a key Static VAR Compensator. There are interplays between selection of equipment options, and selection of balancing |

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| | | strategies to “operate through” moderate level solar storms. Further, commercially available GIC monitors now provide “operating procedure” choices for their programming. At what level should different alarms be set, and to which entity should these alarms be reported? BAs have a “need to know” and critical roles to play, in both advising about equipment upgrades and in making best use of, or de-energizing as needed equipment that impacts the ability to balance loads before, during and after a GMD event. For further information on GIC monitors that are now available, see the Foundation Comments of October 15, 2013 in Maine PUC Docket 2013-00415.Moreover, if the Balancing Authorities are full-time partners in "operating procedures" to be coordinated by the RCs, it is more likely that additional GIC monitors will be installed at key locations, and critical equipment such as SVCs, Extra High Voltage (EHV) transformers, and generators will be protected from tripping or permanent damage. Also, power transmission over High Voltage Direct Current (HVDC) ties that are vulnerable to tripping from GIC will be better planned and protected. Already in New England, the Phase II HVDC tie from Canada has tripped off during a solar storm.A second concern of our Foundation relates to the arbitrary limitation of equipment to be subject to "operating procedures" to those portions of utility networks with high-side voltage of 200 kV or higher. We understand that the lower voltage transformers have higher resistance; hence they are generally less susceptible to GIC entering the bulk power system. But there are so many more transformers under 200 kV--roughly double the total transmission mileage in the U.S. transmission infrastructure--and so many more opportunities for "GIC leakage" into the EHV transmission networks. It appears imprudent to exclude transformers in the 100 kV to 200 kV range from "operating procedures."PowerWorld has estimated that less than 60% of total MVAR enters the bulk power system through transformers at 230 kV or higher, in both New England and in Michigan. Other regions that have not been adequately modeled to date may also incur high "GIC leakage" from transformers with high-end voltage under 200 kV. Transformers supplying these additional MVARs may experience transmission congestion, adverse effects of harmonics through overheating and equipment vibration, and risks of equipment damage or total loss. The economics of "operating procedures" may well demonstrate benefits of some combination of |

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| | | equipment installation and operating procedures to reduce the rate of "GIC leakage" into the bulk power system via transmission sub-systems operating below 200 kV. NERC has not done the financial analysis mandated by FERC Order No. 779, so NERC should not prematurely exclude these grid pathways subject to GMD-induced instability, unreliability, and reduced capacity utilization. It is also notable that much of the specialized equipment designed to provide reactive power or to stabilize voltages within design tolerances operate below 200 kV. Is this equipment to be excluded from protective "operating procedures" under Proposed NERC Standard EOP-010-1? Siemens, for example, identifies many Static VAR Compensators operating at less than 200 kV. CenterPoint's Crosby SVC (IOC 2008) operates at 138 kV. Brushy Hill (1986, Canada) operates at 138 kV. Entergy's Porter SVC in Texas (IOC 2005) operates at 138 kV. CenterPoint Energy's Bellaire (IOC 2008) operates at 138 kV; Exelon's 2 SVCs at Elmhurst operate at 138 kV. Entergy's Prospects Heights SVC near Chicago has 2 SVCs at 138 kV. Northeast's Glenbrook, CT STATCOM operates at 115 kV.In “Appendix 2, Detailed Summary of Power System Impacts from March 13-14, 1989 Geomagnetic Superstorm” of “Meta-R-319, Geomagnetic Storms and Their Impacts on the U.S. Power Grid” by John Kappenman (January 2010, Oak Ridge National Laboratory), a table of system impacts on Page A2-2 shows no less than 10 GIC impacts on equipment operating at a base voltage of less than 200 kV. This is real -world data during a moderate solar storm. In contrast, NERC offers only theorizing in its document, “Network Applicability, Project 2013-03 (Geomagnetic Disturbance Mitigation), EOP-010-1 (Geomagnetic Disturbance Operations), Summary Determination” that networks operating at less than 200 kV would not be affected by GIC. Real world data should trump the technical speculation of NERC. Networks operating at less 200 kV (and over 100 kV) are part of the Bulk Power System and should be included in standards for GMD mitigation.Increasingly, the Bulk Power System is connected to wind power generation, with many wind power systems at ocean boundaries that may import above-average GIC. Wind power systems are generally stepped up to less than 200 kV. Wind power transmission systems are increasingly outfitted with GIC monitors. So, if these facilities are excluded from "operating procedures," will that mean that the near-real-time GIC data now available to wind power operators will not be shared with the RCs? It is |

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| | | notable that in the Maine PUC Docket 2013-00415, with documents retrievable via the Internet, John Kappenman of Storm Analysis Consultants reported in October 2013 that, depending upon the orientation of a solar storm, the single GIC monitor at Chester Maine might report little or no GIC, even in a large solar storm. This is the only near-real-time GIC data received by ISO-New England, the relevant RC. Why would NERC seek to exclude GIC monitors at wind generation-transmission interconnections below 200 kV from "operating procedure" management by the Regional Coordinators? This would appear to be imprudent and is likely to result in needless risks to bulk power system reliability. In FERC Order No. 777, 142 FERC Para 61,208, issued on March 31, 2013, FERC provided a rationale for extending a reliability standard below 200 kV voltages under circumstances where the assets under consideration "are critical to reliability." See FERC Order No. 777 at p. 23, in Docket RM12-4-000. All of the SVCs, STATCOMs, series capacitors, and prospective dynamic VAR compensators with voltage under 200 kV should be considered as equipment "critical to reliability" for purposes of GMD operating procedures.Finally, our Foundation is alarmed that Generator Operators are now excluded from "operating procedure" jurisdiction in the proposed standard. Why?The NERC Drafting Team determined “that Generator Operators should not be among the applicable functional entities because any operating procedure to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment.”We find these rationales to be implausible. Generator Operators have, for more than a decade, utilized formulae provided (by ABB and other vendors) to down-power generation, hence loads on unprotected EHV transformers. There is operating experience with these “down-powering” practices that need to be shared as “best practices” or unacceptable practices. Those Generator Operators that already have installed GIC monitors, working with regional models, have already produced estimated of field voltages that will or will not collapse regional transmission networks. It would be imprudent to wait until every Generator Operators has GIC monitors at every GSU transformer to develop “operating procedures” that can protect critical equipment using cost-effective strategies. Another reason to bring Generator Operators into “operating procedure” practices as soon as possible is to help educate Generator Operators to understand the |

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| | | practical limits of “operating procedures” for Generator Operators with equipment running at “GIC hotspots.” Neutral ground blocking devices not only eliminate virtually all GICs entering GSU transformer, but also reduce vulnerabilities of other GSU transformers that are unprotected within regional networks. The sooner executives of Generator Operators learn whether they will benefit from hardware protecting investments, the better. See the Foundation’s reproduction of a NOAA (Denver) initiative to display the frequency of half-cycle solar GMD events for the period 1958-2007 (Figure 20), indicating an above average risk in the years following solar maxima. The last solar maximum occurred in September 2013. See the Foundation Reply Comment of October 15, 2013 in Maine PUC Docket 2013-00415. FERC’s Order No. 779 seeks expedited protection of the bulk power system, not endless delays of needed protections. Many Generator Operators own and operate GSU transformers that at risk for damage due to GICs entering their GSU transformers and the bulk power system. Some Generator Operators, e.g. NextEra, have spun-off subsidiaries that can qualify their EHV transformers for OATTS cost-recovery by transferring ownership into a closely held transmission company. In either case, Generator Operators are key players in determining whether to downpower during a space weather-warning period. Many Generator Operators are also aware that the harmonics from GICs that enter their systems cause both overheating and vibrational effects on other equipment such as: generator stators, stator cooling pipes, and generator turbines. To exclude Generation Operators from "operating procedures" appears unfounded and a possible aggravating factor in a severe solar geomagnetic storm. Lastly, NERC needs to address what can be done to protect high-cost,long-replacement-time equipment during a severe solar storm, such as the New York Railroad storm of May 1921. Will the Nuclear Regulatory Commission preemptively order the de-energizing of all nuclear generating facilities and associated GSU transformers? Should the President order the de-energizing of all unprotected GSU transformers, including those without neutral ground blocking or designs projected to survive impending GMD events? If so, how will the Generator Operators protect their equipment, train personnel to validate and authenticate de-energization orders, and plan for optimal "black start" procedures? Excluding Generation Operators from the jurisdictional scope of "operating procedures" appears |

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| | | to be based on the convenient but false assumption that the only solar geomagnetic storms for which electric utilities need prepare are those of moderate strength and short duration.We cannot in good conscience vote "yes" for a proposed standard for "operating procedures" that excludes Balancing Authorities, excludes Generator Operators, excludes critical equipment operating at under 200 kV, and excludes operators of GIC monitoring equipment from a mandate to share safety-related information in near-real time. NERC and the electric utility industry can achieve more effective standards. If this standard is approved by NERC as proposed, FERC should require key modifications in its review process. |
| Public Service Enterprise Group | No | R2 states “Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan.” We agree, but in R1 which requires such a plan, there is not requirement related to R2. We believe R1 should have subpart 1.1 rewritten as follows:1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area WHICH INCLUDE AN ACTIVITY TO DISSEMINATE FORECASTED AND CURRENT SPACE WEATHER INFORMATION. |
| SPP Standards Review Group | No | We propose changing the wording in Section 4.1.2 under Applicability to read:Transmission Operator with a Transmission Operator Area that includes a power transformer with a high-side, wye-grounded winding with a terminal voltage greater than 200 kV.This clarifies that the 200 kV winding is the high-side, wye-grounded winding.We suggest changing the ‘the Reliability Coordinator Area’ to ‘its Reliability Coordinator Area’ in R1.2.We suggest replacing ‘respective system’ with ‘Transmission Operator Area’ in R3. This language would then parallel that of R1. |
| American Electric Power | No | While AEP welcomes the removal of the word “coordinate” as an action performed by the RC, the word is now used as something that is done by the Operating Plan. Despite this change, and because the RC is required to implement the Operating Plan, there still appears to be an “implied” obligation where the RC must coordinate. This term remains |

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| | | vague, and more specific text should be used in its place such as "affirm the compatibility of Operating Procedures and Operating Processes among the entities within the Reliability Coordinator Area."Operating Plans developed by Reliability Coordinators may be quite different from area to area, which may be necessary in some circumstances. However, because AEP serves in multiple Operating Regions, we hope that the various Operating Plans, when feasible, are uniform for the most part. R1 states that the Operating Plan must coordinate GMD Operating Procedures, but makes no mention of the Operating Process as required in R3. Similarly, R1.2 requires a process to review GMD Operating Procedures but again makes no mention of reviewing Operating Processes. We recommend adding "Operating Processes" in R1 and R1.2, so that R1 reads "Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area." and that R1.2 reads "A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators in the Reliability Coordinator Area." |
| Independent Electricity System Operator | Yes | (1) We agree with all the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. However, we believe Part 1.2 should be expanded to convey the need for developing recourse. Part 1.2 stipulates that the RC's GMD Operating Plan shall include:1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area.When a RC's review of the TO's operating procedures finds something lacking, then the recourse to make corrections should be made more clear. We suggest Part 1.2 be revised as follows:1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area, and direct the Transmission Operators to correct deficiencies, if any.If the SDT accepts this recommendation, please make a mirror change in R3 that will require the TOP to comply with the RC's directive for correcting the deficiencies.(2) R2 as written is unclear on to whom the weather condition is to be provided. We suggest R2 to be clear that the RC is disseminating |

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| | | space weather information to TOPs, as stated in the Background Information in the Comment Form “A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in the Reliability Coordinator Area (RCA).(3) R3 - The term ‘Operating Process’ is unnecessary and inconsistent with the wording in R1. We suggest to remove “or Operating Process” from R3 in the statement “Each Transmission Operator shall develop, maintain, and implement an Operating Procedure or Operating Process...”. |
| ACES Standards Collaborators | Yes | 1) The draft standard is much improved over the previous version. We thank the drafting team for removing the administrative requirements and removing BA applicability. We also agree that the standard does address the FERC directive. However, we believe there is another option that is as equally effective, is actually more efficient than writing a new standard and eliminates the redundancy that this proposed standard creates. The other option is to rely on existing standards. TOP-001-1a R2 and R8 already require the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. EOP-001-2 R2.2 requires the TOP to “develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.” IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective. Since these standards requirements are applicable at all times including during GMD events, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements. |

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| Hydro One | Yes | A process for the RC to review the GMD Operating Procedures of TOs in the RCA from the point of view of coordination is needed. |
| Colorado Springs Utilities | Yes | o Thank you for your efforts. The standard drafting team has not provided sufficient technical justification for the 200 kV threshold. Utility research indicates that the threshold should begin more around the 300kV threshold. |
| Electric Reliability of Texas, Inc. | Yes | ERCOT generally supports the SDT's efforts in developing the draft GMD standard and believes it is on the right track. However, the SDT should consider the following comments in the development of future versions.Most of the requirements seem to be concentrating upon the administration of “having procedures”. The standard should say “what” is required, while minimizing the required administration activities.1) Applicability Section The SDT should consider the role of GOPs in the standard. The standard in both its initial and revised form does not address the GOP function. GOPs may have GMD operating plans in place. As the whitepaper on applicable functions noted - “Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure.” Given that generators may have GMD procedures in place, the standard should reflect those procedures on a stand alone basis and as inputs into the larger operational GMD procedures. The failure to consider those plans in developing and coordinating the broader scope operational plans would create a disconnect between core operational roles. Such disconnects could undermine the effective and efficient management of GMD events potentially creating an undesirable reliability impact on the interconnection. Accordingly, the SDT should consider revisions to include the GOP function to ensure generator GMD procedures are considered and reflected in the larger scope GMD operational procedures. These plans should be coordinated with the relevant TOP and RC plans in a coordinated manner that is ultimately overseen by the RC, as proposed in the standard. 2) Requirement 1.2 The revised standard removes the coordination/compatibility determination role of the RC. It seems the RC should be performing these roles to |

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| | | ensure effective and efficient operations in the context of a GMD event. It is not clear that a simple "review" role is adequate to achieve that outcome. The SDT should reconsider whether the RC should have the ability/authority to address any potential conflicts in plans pursuant to a coordination/compatibility determination role. If the revision was intended to simply be a "clean-up" edit, and that the coordination role is adequately covered in the R1 coordination role, R1 should reference R 1.2, so it is clear that the plans referenced in R1 are defined in terms of the specific functional entity referenced in R1.2.3) Measure 1 The revisions to M1 includes language that calls for evidence related to implementation to be that which demonstrates the entity performed the action "as called for in the GMD Plan...".While ERCOT understands the value of linking implementation evidence to the plan, the way it is drafted it could be interpreted very rigidly such that any operational deviation from the plan would be a violation. Obviously if you have a plan it should be used, but neither the standard nor the measure should be so rigid that if the operators cannot deviate from the plan if necessary based upon unintended circumstances without the risk of noncompliance with this requirement - entities should be able to take actions outside the four corners of the plan if necessary, and the standard and compliance measures should clearly accommodate such actions to avoid unintended consequences where the best operational actions are not taken because entities do not want to risk noncompliance.4) Requirement 2 Requirement 2 mandates that the RC share forecasted and current space weather information in accordance with its plan. As an initial matter, this implicitly requires RCs to have forecasted and current space weather information in our plans even though the substantive requirements related to the plan in R1 don't require that. This creates ambiguity in terms of whether that is a substantive obligation for the plan. For example, can an RC not have this in their plan, and, if so, does that make that requirement inapplicable in an audit? Another potential ambiguity related to this requirement is that there is no direction in terms of the entities the RC is required to disseminate this information to under the requirement. ERCOT understands the standard leaves this to the RC plan, but again, does that mean the RC does not have to have this in its plan? If this obligation is retained, the scope should be aligned with the functional entities in the standard that have GMD procedural roles (currently just TOPs |

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| | | - although as noted ERCOT questions whether GOPs need to be included in the standard). Also, if this is going to be a plan requirement that should be explicit. To make it clear, it should be established as a substantive component of the plan as part of R1. However, ERCOT does not support this as a substantive requirement. The standard should dictate the substance of functional entity plans.ERCOT also questions the need for the RC to disseminate that information. The information can be obtained by other functional entities independent of RC dissemination, and that obligation, if the SDT elects to require entities to obtain this information, should be assigned to those entities. As drafted, this unnecessarily creates an opportunity for RC non-compliance with what is really administrative obligation i.e. distributing information that can be obtained independent of the RC. To the extent there is an inconsistency risk in terms of the sources/substance of this information, that risk could be managed by the RC coordination role.In addition to the above issues, the requirement is otherwise vague and ambiguous in terms of the scope of the information disseminated. For example, what is the timing for the dissemination? Again, the draft language leaves this to the RC plan, but as discussed, it is not clear if the RC has to have anything related to this, and if it does not, what the impact of that would be in an audit. If this implicitly requires the RC to have this process in its plan, the issue is what is the scope for all aspects - e.g. audience, timing, etc.? Granted the way it is drafted the RC has complete discretion, but there is a concern whether that discretion will be respected by the ERO in the exercise of its CMEP function.To mitigate the potential issues with this requirement, ERCOT believes it should be removed because the standard should require a plan, but should not dictate the substantive components of the plan. Alternatively the standard should be revised to make the obligations explicit and clear with respect to what is required - e.g. R 3.1 makes it clear that TOPs are required to have a process to obtain space weather information.5) Requirement 3 Related to the above comments on R2, R3 requires TOPs to get space weather info. Given this independent obligation, why does the RC have an obligation to disseminate that info? As discussed, it is unnecessary and creates unnecessary compliance risk.6) Requirements 3.2 and 3.3 As drafted, these requirements seem too prescriptive. While it is reasonable that a plan establishes actions relative to specific conditions. However, |

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| | | the language should be clear that these are recommended actions, but are illustrative and non-exclusive.  Functional entities should have the flexibility necessary to take actions outside of the plan if operating conditions change and counsel for operating actions outside of the four corners of the plan.7) Measure 3 Similar to the above comment on Measure 1, as drafted, Measure 3 could be interpreted in a manner that is too prescriptive and limiting, which could create the risk of undermining effective operations by limiting operator actions to the four corners of the plan or risk noncompliance risk.  This would undermine the operational flexibility necessary to act outside of the plan if system conditions warranted such actions without risking violation of the requirement. |
| SERC OC Review Group | Yes | In R1 the requirement calls for the RC to review an “Operating Procedure”.  We request the SDT to consider adding “Operating Process” so it is consistent with R3. |
| Duke Energy | Yes | In R1.2, the requirement calls for the RC to review an “Operating Procedure”.  Duke Energy recommends  adding “Operating Procedure or Operating Process”for consistency with R3. |
| US Bureau of Reclamation | Yes | The Bureau of Reclamation (Reclamation) appreciates the drafting team’s decision to require Reliability Coordinators (RCs) to disseminate space weather information rather than requiring each TOP to acquire and disseminate space information. |
| Northeast Power Coordinating Council | Yes | The Time Horizon brackets for Requirement R1 incorporate four (4) Time Horizons shown as: [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]It is not clear which Time Horizon goes with what part of Requirement R1.  Suggest adding the clarification in a Rationale Box as follows:Development of the GMD Operating Plan is in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan is in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan is in the Same-Day and Real-Time Time Horizons. |

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| ISO/RTO Council Standards Review Committee | Yes | We agree with most of the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. Nevertheless, we offer the following comments intended to further improve the standard.1. Certain wording in the proposed R2 introduces an unclear requirement in R2 and implied requirements in R1. R2 stipulates that the RC shall dissemintate forecasted and current space weather information “as specified in the Reliability Coordinator's GMD Operating Plan”. It is not clear what is it in the GMD Operating Plan that the RC must follow: is it the entities to whom the RC need to disseminate the information, or is it the forecast and current space weather information, or is it the timing for the dissemination, or a combination or all of the above? R1 does not provide this detail.We suggest the SDT to either add the detail in R1, or to remove or reword the phrase “as specified in the Reliability Coordinator’s GMD Operating Plan” to remove the uncertainty and implied requirement.2. We would also suggest some wording change to R1, which currently stipulates that:R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures within its Reliability Coordinator Area.A plan does not “coordinate”. Depending on the intent of the requirement - whether it mandates the RC to coordinate the GMD operating procedure or the RC to have a GMD operating plan that contains the coordinated operating procedures, and to more specifically indicate who to coordinate with, a more appropriate wording could be:”Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan to coordinate GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.”Or, the wording could be:”Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that reflects (or covers or stipulates) the coordinated GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.” |
| Xcel Energy | Yes | We have the following additional comments, but don’t view them as show stoppers.Because R2 specifies that the RC must disseminate space weather information |

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| | | as specified it he RC GMD Op Plan, it would seem logical that there be a sub requirement in R1 that requires the RC has a process to distribute the space weather and list the entities and/or functions for distribution.R3.1 seems unnecessary since R2 requires the RC to disseminate space weather info, presumably the TOPs are included. It isn't clear what steps or tasks an entity would have to 'receive' space weather information. |
| NERC Compliance Policy | Yes | |
| Bonneville Power Administration | Yes | |
| Arizona Public Service Co. | Yes | |
| PacifiCorp | Yes | |
| Manitoba Hydro | Yes | |
| Public Utility District No.1 of Snohomish County | Yes | |
| Idaho Power | Yes | |
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| Oncor Electric | Yes | |

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| Delivery Company LLC | | |
| NV Energy | Yes | |
| Seminole Electric Cooperative, Inc. | | Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of system topology, including geographical orientation, in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures:"An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures."Seminole acknowledges that the SDT did not adopt this suggestion during the last comment period for the reason that the SDT did not wish to begin naming criteria that could be utilized in documenting an Operating Plan, i.e., an exhaustive list. However, while reviewing the SDT's Network Applicability document posted with this Standard, NERC incorporated two out of the three Network Definition Considerations into the Proposed Standard, those two being the wye-grounded power transformer requirement and the lower limit voltage of 200 kV, while not adopting the system topology consideration. Seminole agrees with NERC that this is an important consideration in assessing GMD impacts and believes that this should be incorporated into the Standard in a manner that does not restrict additional considerations. As previously noted, the above suggested language comes directly from the SAR for this project. |

2. **Do you agree that the VRFs and VSLs support the reliability objectives of the standard and meet FERC and NERC guidelines? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

**Summary Consideration:** The drafting team thanks all who commented on the VRFs and VSLs. The Standard Drafting Team applied the NERC criteria and FERC Guidelines when proposing VRFs and VSLs for EOP-010-1. A justification has been posted to the project page (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx).

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| ACES Standards Collaborators | No | Because we question the need for the standard at this juncture, we cannot support the VSLs or VRFs. At best, the VRFs should all be low. For a requirement to be assigned a Medium VRF, a single violation of the requirement would have to "directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system" as defined in the Medium VRF definition. A single violation of any of these requirements will not "directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system." Other standards would have to be violated first. For example, both TOP-002-2.1b R8 and TOP-004-2 R6.1 would have to be violated as well to effect the electrical state, monitoring and control of the bulk electric system. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Other requirements that would have to be violated include EOP-001-2 R2.2 and IRO-014-1 R1. |
| American Electric Power | No | We do not believe failure to meet R3.3, i.e. failure to terminate the Operating Procedure or Process after a GMD event, justifies a Medium VRF. Instead, a "Low" VRF is |

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| | | recommended. |
| Flathead Electric Cooperative, Inc. | No | |
| CPS Energy | No | |
| Centerpoint Energy | No | CenterPoint Energy does not believe the lack of a documented procedure should produce a High VRF or Severe VSL. |
| Public Utility District No.1 of Snohomish County | Yes | Because GMD can be a wide area event the TOP efforts should focus on coordinating operations and procedures with the RC. Also, GMD is a high-impact, low-frequency event so overall risk to the TOP should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System. |
| SPP Standards Review Group | Yes | We would prefer to see the VRFs at Low rather than the assigned Medium, but can live with them as proposed. |
| Northeast Power Coordinating Council | Yes | |
| SERC OC Review Group | Yes | |
| Duke Energy | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |
| Bonneville Power Administration | Yes | |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| Arizona Public Service Co. | Yes | |
| PacifiCorp | Yes | |
| Colorado Springs Utilities | Yes | |
| US Bureau of Reclamation | Yes | |
| Foundation for Resilient Societies | Yes | |
| Manitoba Hydro | Yes | |
| Hydro One | Yes | |
| Idaho Power | Yes | |
| Independent Electricity System Operator | Yes | |
| Electric Reliability of Texas, Inc. | Yes | |
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| Oncor Electric Delivery | Yes | |

| Organization | Yes or No | Question 2 Comment |
| --- | --- | --- |
| Company LLC | | |

3. **The Implementation Plan provides conditions for determining when the Requirements in EOP-010-1 become effective in each jurisdiction. Do you agree with the Implementation Plan as written? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

**Summary Consideration:** The drafting team thanks all who commented on the Implementation Plan. Some stakeholders also commented that the six-month implementation period was too short. The drafting team believes that the requirements of the proposed standard can be met within that period. One commenter expressed concern that the stage 2 standards could affect the implementation or applicable entities of EOP-010-1. The drafting team believes the scope and purpose of the two stages in Project 2013-03 are properly established and separate as described in the Standard Authorization Request.

| Organization | Yes or No | Question 3 Comment |
| --- | --- | --- |
| CPS Energy | No | Implementation should be at the regional level |
| Arizona Public Service Co. | No | The implementation period should be no less than 1 year, 6 months implementation time would cause significant strain and will not allow an effective procedure to be developed. |
| Oncor Electric Delivery Company LLC | No | The Implementation Plan timeline calls for implementation 6 months from the standard approval or on the first day following the retirement of IRO-005-3.1a. This timeline does not provide sufficient time to create the necessary procedures or processes and train necessary personnel to those processes and procedures. The preferable timeline would be for implementation 12 months from the standard approval or on the first day following the retirement of IRO-005-3.1a, whichever is later. |
| Flathead Electric Cooperative, Inc. | No | |
| Xcel Energy | Yes | none |

| Organization | Yes or No | Question 3 Comment |
|---|---|---|
| Public Utility District No.1 of Snohomish County | Yes | Public Utility District No.1 of Snohomish County agrees in general, however appropriate implementation time should be given so that the Reliability Coordinator ("RC") has the time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions. |
| US Bureau of Reclamation | Yes | Reclamation appreciates the drafting team's efforts to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010 Requirement R2 are effective at the same time. |
| SPP Standards Review Group | Yes | The treatment of the Effective Date in the standard appears to address the issue of implementation in the Canadian provinces. Hopefully this will resolve the issue. |
| ACES Standards Collaborators | Yes | While we continue to believe there is another equally efficient and more efficient alternative to development of this standard, the implementation plan is reasonable within the constraints of this standard. However, we have concerns that the second phase of this project may alter the work done in phase one, including modifications to the implementation plan and the entities that could be subject to compliance with this standard. |
| Northeast Power Coordinating Council | Yes | |
| NERC Compliance Policy | Yes | |
| SERC OC Review Group | Yes | |
| Duke Energy | Yes | |
| ISO/RTO Council Standards Review Committee | Yes | |

| Organization | Yes or No | Question 3 Comment |
| --- | --- | --- |
| Bonneville Power Administration | Yes | |
| PacifiCorp | Yes | |
| Colorado Springs Utilities | Yes | |
| Foundation for Resilient Societies | Yes | |
| Manitoba Hydro | Yes | |
| Hydro One | Yes | |
| Idaho Power | Yes | |
| Independent Electricity System Operator | Yes | |
| Electric Reliability of Texas, Inc. | Yes | |
| Tri-State Generation and Transmission Association, Inc. | Yes | |
| NV Energy | Yes | |

**4. If you have any other comments for the drafting team to consider that you haven't already mentioned, please provide them here:**

**Summary Consideration:** The drafting team thanks all who responded. The drafting team adopted a number of suggestions for clarifying the standard. A small number of commenters suggested substantive changes such as adding Requirements or language, but the drafting team does not believe there is a consensus to make substantive changes to the standard at this time. A summary of comments and the drafting team's response is provided below:

- **Predetermined conditions required for GMD Operating Procedures or Operating Processes. A commenter suggested the qualifier "if known" be added to Requirement R3 part 3.2 so entities without a study or GIC measuring equipment would not be required to include predetermine conditions for operator actions in the GMD Operating Procedure or Operating Process.** The drafting team believes that the requirement as written provides the flexibility to use good professional judgment to develop effective GMD Operating Procedures and Operating Processes.
- **Tailoring of operating procedures. A commenter requested that language be included in Requirement R3 to reflect that entities are allowed to consider various entity-specific factors in developing GMD Operating Processes or Operating Procedures.** The drafting team agrees with the principle that an entity can consider entity-specific factors in developing its process and procedure and has provided for this in the standard. The following has been added to the rationale box to describe the drafting team's intent: "In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology."
- **Transmission Operator responsibility to receive space weather information. A commenter stated that Requirement R3 part 3.1 should be removed since Requirement R2 placed responsibility for providing this information on the RC.** The drafting team believes that receiving space weather information is an essential component to GMD Operating Procedures or Operating Processes. EOP-010-1 recognizes that Transmission Operators may use several sources in addition to the Reliability Coordinator's disseminated forecast information to obtain more detailed local or system-specific information.
- **Requirement to ensure coordination between Reliability Coordinators. A commenter recommended a requirement be included added to require adjacent Reliability Coordinators to share their respected GMD Operating Plans.** The SDT believes coordination between and among Reliability Coordinators is adequately addressed in existing IRO standards. (Refer to IRO-014, Requirement R1).
- **A commenter recommended revising the SAR to include the term Operating Processes as currently used in the standard.** The SAR, as accepted by the Standards Committee, adequately defines the project scope without the recommended change.

- **A commenter suggested alternate wording for Requirement R3 part 3.3 (terminating the GMD Operating Procedure or Operating Process).** The drafting team considered the suggested alternate wording and determined that the suggested change did not provide additional clarity.
- **A commenter identified a correction needed in the Functional Entity Applicability whitepaper that the drafting team has incorporated.** The revised Functional Entity Applicability whitepaper (clean, and redline showing the changes made) has been posted on the project page (.http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx)
- **A commenter recommended a change to Requirement R3 to indicate that the GMD Operating Procedures or Operating Processes were intended to mitigate the effects of GMD events.** The drafting team considered the proposed language and determined that the suggested change did not provide additional clarity.
- **A commenter reiterated that system studies should be performed before operating procedures should be required.** The drafting team believes that the standard as written provides the flexibility to use good professional judgment to develop effective GMD Operating Procedures and Operating Processes.

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| ISO/RTO Council Standards Review Committee | No | |
| Manitoba Hydro | No | |
| Hydro One | No | |
| Flathead Electric Cooperative, Inc. | No | |
| Idaho Power | No | |
| Oncor Electric Delivery Company LLC | No | |
| CPS Energy | No | |

| Organization | Yes or No | Question 4 Comment |
| --- | --- | --- |
| Arizona Public Service Co. | Yes | Suggest changing R3.2 to as follows:System Operator actions to be initiated based on predetermined conditions, if known to be a susceptible to GMD. During the Webinar, it was pointed out that TOP is not required to have a study or measurement to find the predetermined conditions and most TOP would not know of such conditions existing in their system. The suggested language change would make it clear that they are not required to know the predetermined conditions. |
| ACES Standards Collaborators | Yes | (1) Requirement R2 should be made a sub-part of Requirement R1 to avoid double jeopardy and because it is essentially a constraint on the Operating Plan. If a registered entity fails to write an Operating Plan, it will also fail to include in its Operating Plan the method for disseminating space weather. Since violations are assessed per requirement, one compliance failure could result in two compliance violations of R2 and R3. Thus, if R2 is written as a sub-part of R1, failure develop an Operating Plan will be assessed as a single violation of the combined requirement. Furthermore, R2 essentially is a requirement for what should be contained in the Operating Plan and, therefore, more appropriately belongs as a sub-part of R1. (2) Part 3.1 in R3 is unnecessary and redundant with other requirements. R2 already compels the RC to disseminate space weather information. Because the RC is a higher authority than the TOP, the TOP is already required to receive the information as a result by implication. The RC's authority is documented in IRO-001-1a R3 and R8. The RC may issue directives to the TOP to follow its GMD Operating Procedure or Process while disseminating information about severe space weather. Furthermore, NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. Codifying a process that is already in place and works effectively only perpetuates the existing compliance model that places too much emphasis on documentation and not enough on reliability. (3) The SAR should be modified to indicate that Stage 1 will require registered entities to develop |

| Organization | Yes or No | Question 4 Comment |
| --- | --- | --- |
| | | and implement Operating Processes and Operating Plans in addition to Operating Procedures. The SAR only references the development and implementation of Operating Procedures which is not consistent with the standard that includes Operating Plans and Operating Processes. (4) We believe the literal meaning of the language in R3 Part 3.3 is not what is intended by the drafting team. As written, the language could be read to literally mean that the Operating Process or Operating Procedure must include language for retiring the Operating Process or Procedure. The problem is with the use of "terminate the Operating Procedure or Operating Process." Terminate means to come to an end. Thus, terminating the Operating Procedure or Operating Process which are documents means to end the document. Obviously, the purpose is to terminate the use of the Operating Procedure or Operating Process when the GMD event has ended. We suggest using the language from the SAR for R3 Part 3.3 as it is clearer and has a more exact meaning of what is intended. The language in the SAR is: "Criteria for discontinuing the use of Operating Procedures at the conclusion of a GMD event." (5) The Long-term Planning Time Horizon for R1 and R3 should be removed. The functional entities to which the standard applies are not planning entities per the functional model and have no long-term planning responsibilities. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions." An operating plan contains operating procedures and processes which are applied in real-time operations. (6) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | their RC?  If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will satisfy this required coordination.  (7)  The white paper supporting functional entity applicability should be modified.  On page three, the last sentence just before the “Justification for Omitting Functional Entities” section is inconsistent with the standard.  It states that “some procedures can be put in place by all TOPs.”  The standard limits the procedures to only TOPs with a transformer with a high-side wye-grounded winding greater than 200 kV.  Please modify the sentence in the whitepaper for consistency with the standard.  (8)  We do not believe the science of how GMDs impact the electric grid is settled.  This is evidenced by multiple reports with significantly varying conclusions.  While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extreme GMD events, the reports may not emphasize the geographic risk of the problem.  For example, does a utility in South Florida have the same risk as a utility in northern Maine?  If the risks are different, a requirement for an operating procedure for all entities including the southernmost entities is premature at this point.  We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative.  We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies as documented in our responses to other questions.(9) Thank you for the opportunity to comment. |
| Colorado Springs Utilities | Yes | 1. Thank you for all of your work SDT!  2. For the record.  We have concern over the fact that action is being required prior to defining the risk?  A blind shotgun approach consumes a lot of unnecessary resources, as it is anticipated that there are many entities that will not be at risk to GMDs.  We understand that FERC is pushing for action, but think that their push should be founded on established risk. |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Florida Municipal Power Agency | Yes | According to the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers connected in a grounded wye configuration. This is the primary reason for FMPA's negative vote.FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. The resistance of 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line. Although FMPA believes the threshold should be raised to 300 kV, we can "live" with a 200 kV threshold if the applicability to 200 kV is to TOPs that operate three single leg core design transformers connected in a grounded wye configuration. |
| Bonneville Power Administration | Yes | BPA recommends the drafting team change the language of the first sentence of R3, from “Each Transmission Operator shall...or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system.” To “Each Transmission Operator shall...or Operating Process intended to mitigate the effects of GMD events on the reliable operation of its respective system.” |
| Duke Energy | Yes | Duke Energy would like to thank the SDT for their response to stakeholder comments. |
| Foundation for Resilient Societies | Yes | For further background information on the Foundation's support of wider jurisdiction for coordinated "operating procedures" see our March 2013 case study of Maine and ISO-New England in a solar geomagnetic storm, found at www.resilientsocieties.org and the Foundation's comments responsive to queries by the Maine Public Utilities Commission, in MPUC Docket 2013-00415 (Oct 4, 2013), and our Supplemental and |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | Reply Comments in that same Docket (October 15, 2013). |
| Nebraska Public Power District | Yes | NPPD supports the comments submitted by the Southwest Power Pool. In addition we would like to add this comment:"The drafting team is requiring operating procedures to be in place prior to studying the GMD effects on the TOP system. To determine what effects the GMD will have on the TOP's system, the studies should be preform first and then the operating procedures developed. The drafting team is requiring generic operating procedures which may or may not address the GMD issues on the TOP's system. It makes more sense to delay the implementation of the operating procedures until the studies have been performed." |
| ReliabilityFirst | Yes | ReliabilityFirst votes in the affirmative because this standard will help to mitigate the effects of geomagnetic disturbance (GMD) events by requiring the Reliability Coordinator to implement Operating Procedures and the Balancing Authorities and Transmission Operators to implement Operating Plans. ReliabilityFirst offers the following comments for consideration:1. Requirement R1 - To be consistent with the language in Requirement R3, ReliabilityFirst believes the term "Operating Process" should be added to Requirement R1. Furthermore, Requirement R1 should include a statement tying it back to the Transmission Operator's Operating Procedure or Operating Process in Requirement R3. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures [and Operating Processes, as developed in Requirement R3,] within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:..."2. Consideration for new Requirement R4 - ReliabilityFirst submitted this comment during the last comment period but believes it may have been overlooked (i.e., we believe it was not addressed in the consideration of comments report). ReliabilityFirst recommends including a new Requirement R4 which would require adjacent Reliability Coordinators to share their respected GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | should be aware of each other's GMD Operating Plans. |
| Oklahoma Gas & Electric | Yes | The Standard, as written, requires entities to have a plan, but it fails to identify a clear and measurable expected outcome, such as a stated level of reliability performance, a reduction in a specified reliability risk (prevention), or a necessary competency. |
| Northeast Power Coordinating Council | Yes | The text of the "Effective Dates" section should be consistent with the EOP family of standards to reduce the variance between EOP Standards.Regarding Requirement R1 and its Measure M1, times for completion need to be added.  The Violation Severity Levels have to be revised accordingly.The contents of the Rationale Boxes for R1 and R3 as they shown are obvious, and can be removed.  In the response to Question 1 above we suggested an addition to the Rationale Box for R1. The Rationale Box for R2 should not repeat wording from R2. |
| American Electric Power | Yes | The time horizon "Long-term Planning" seems more appropriate for the Stage 2 aspect of this GMD standard, and not for the Stage 1. Please provide carification for how Long-term Planning is to be applied for R1 and R3 as well as justification for doing so.Although this may be ouside the scope of this project team, we encourage NERC to resolve the discrepancies between the definition of Long-term Planning as provided in NERC's Time Horizon and the definition of "Long-Term Transmission Planning Horizon" in the NERC Glossary of Terms.AEP recognizes the perceived urgency of this project, supports the objective of the proposed standard, and appreciates the efforts of the drafting team. Our negative vote is driven solely by our desire for additional clarity as stated in our comments. AEP foresees voting in the affirmative once the issues and concerns expressed in this response are addressed in future versions of the draft. |
| Tri-State Generation and Transmission Association, Inc. | Yes | Tri-State is still concerned with the Standard Drafting Team's decision setting the limit of applicable transformers from >200kV versus >300kV. This critical decision will have significant cost and time ramifications on the industry. The workload for Tri-State will increase nearly five-fold based on the amount of transformers that fall into the 200-300kV range. We appreciate the work that the volunteer task force has accomplished in |

| Organization | Yes or No | Question 4 Comment |
| --- | --- | --- |
| | | helping to prepare the NERC “Network Applicability” paper, but Tri-State believes such a critical decision in setting the limit should be based on more extensive knowledge. The “Network Applicability” justification for including 200kV circuits is only based on an analysis of a small simulated network consisting of two 500/230kV autotransformers with only a few lines running into and out of that station. That analysis, summarized in Table A1 (pg. 7), predicts a decrease of GIC from 5.5 to 2.8 Amps if the 230kV elements are included. The study also estimates an increase in var absorption from 12.5 to 14 Mvar if the 230kV elements are included. Tri-State suggests that these slight variances are well within the error range in the overall assumptions for the many parameters used to predict GIC itself. Parameters such as the line induced kV/km, the magnitude and duration of solar events, the deep earth soils geology, accuracy of the transformer models, ground grid resistance (which may vary season to season), etc. Our suggestion is to give the NERC task force increased time to do research and in the meantime adopt a criteria of detailed analysis of >300kV with a 10% safety factor added for the possible <300kV impact. |
| SPP Standards Review Group | Yes | We want to thank the drafting team for taking the time to provide summary responses to help the industry’s understanding of the changes even though they didn’t have to. |
| PacifiCorp | Yes | |
| Public Utility District No.1 of Snohomish County | | Although GMD and Geomagnetically Induced Currents (“GIC”) have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufacturers. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on the level of impact a GMD can have on the BES and what level of risk a GMD poses compared to other adverse impact events. |
| SERC OC Review Group | | We would like to thank the SDT for their responses to stakeholder comments.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | position of the SERC Reliability Corporation, or its board or its officers. |

END OF REPORT