UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ____________**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD
TPL-007-4

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby requests Commission approval of proposed Reliability Standard TPL-007-4 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*) (**Exhibit A**), the associated implementation plan (**Exhibit B**), the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit C**), and the retirement of currently effective Reliability Standard TPL-007-3. The NERC Board of Trustees ("Board") adopted proposed Reliability Standard TPL-007-4 on February 6, 2020.

Proposed Reliability Standard TPL-007-4 requires owners and operators of the Bulk Power System ("BPS") to conduct initial and on-going vulnerability assessments of the potential impact of defined geomagnetic disturbance ("GMD") events on BPS equipment and the BPS as a whole. The modifications in the proposed standard address the Commission's directives in Order No. 851[4] related to requirements for Corrective Action Plans. Specifically, and as discussed further herein, the proposed modifications would: (i) require entities to develop Corrective Action Plans for

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1 16 U.S.C. § 824o (2018).

2 18 C.F.R. § 39.5 (2019).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 851, 165 FERC ¶ 61,124 (2018) ("Order No. 851").

vulnerabilities identified through supplemental GMD Vulnerability Assessments; and (ii) require entities to seek approval from the ERO of any extensions of time for the completion of Corrective Action Plan items. NERC requests that the Commission approve the proposed Reliability Standard and related elements as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve the proposed implementation plan (**Exhibit B**).

Pursuant to Section 39.5(a) of the Commission's regulations,[5] this petition presents the technical basis and purpose of proposed Reliability Standard TPL-007-4, a summary of the development history (**Exhibit F**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672 (**Exhibit E**).[6]

I. SUMMARY

Proposed Reliability Standard TPL-007-4 requires entities to conduct initial and on-going assessments of the potential impact of two defined GMD events, the benchmark GMD event and the supplemental GMD event, on BPS equipment and the BPS as a whole. The benchmark GMD event is intended to simulate the wide area impacts of a severe GMD event. The supplemental GMD event is designed to account for the localized peak effects of severe GMD events on systems and equipment. In the standard, the assessments based on these defined events are referred to as benchmark GMD Vulnerability Assessments and supplemental GMD Vulnerability Assessments, respectively. If entities identify system performance issues through their GMD Vulnerability Assessments, they must take action to mitigate these issues.

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5 18 C.F.R. § 39.5(a).

6 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) ("Order No. 672").

Proposed Reliability Standard TPL-007-4 improves upon the currently effective version of the TPL-007 standard by enhancing requirements related to Corrective Action Plans as directed by the Commission in Order No. 851. In this Order, the Commission approved Reliability Standard TPL-007-2 but directed NERC to revise the TPL-007 standard as follows:

- revise the standard to require Corrective Action Plans for assessed supplemental GMD vulnerabilities;[7] and
- replace the provision in Requirement R7 Part R7.4 that would allow entities to self-extend Corrective Action Plan implementation deadlines with a process through which extensions of time are considered on a case-by-case basis.[8]

The proposed standard addresses the Commission's Order No. 851 directives by:

- requiring an applicable entity to develop a Corrective Action Plan if system performance issues are identified through the supplemental GMD Vulnerability Assessment; and
- requiring an applicable entity to seek approval for any requests to extend Corrective Action Plan implementation deadlines, requests that NERC and the Regional Entities would then consider on a case-by-case basis.

For these reasons, and as discussed more fully in this petition, NERC respectfully requests that the Commission approve the proposed standard as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[7] *See* Order No. 851 at PP 29 and 39.

[8] *Id.* at P 54.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:[9]

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III. BACKGROUND

A. Regulatory Framework

In the Energy Policy Act of 2005,[10] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS. Congress also entrusted the Commission with certifying an Electric Reliability Organization ("ERO") charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.[11] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[12] Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become

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[9] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

[10] 16 U.S.C. § 824o.

[11] *Id.* § 824o(b)(1).

[12] *Id.* § 824o(d)(5).

mandatory and enforceable in the United States and each modification to a Reliability Standard that the ERO proposes should be made effective.[13]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[14] and Section 39.5(c) of the Commission's regulations, "the Commission will give due weight to the technical expertise of the Electric Reliability Organization" with respect to the content of a Reliability Standard.[15]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[16] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[17]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[18] and thus satisfy certain of the criteria for approving Reliability Standards.[19] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the

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[13] 18 C.F.R. § 39.5(a).

[14] 16 U.S.C. § 824o(d)(2).

[15] 18 C.F.R. § 39.5(c)(1).

[16] Order No. 672 at P 334.

[17] The NERC Rules of Procedure is available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[18] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250.

[19] Order No. 672 at PP 268, 270.

comments of all stakeholders, and stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. Procedural History of Proposed Reliability Standard TPL-007-4

This section summarizes the history of the TPL-007 standard and the development of proposed Reliability Standard TPL-007-4.

1. Reliability Standard TPL-007-1

On January 21, 2015, NERC filed a petition requesting Commission approval of Reliability Standard TPL-007-1, the second-stage GMD Reliability Standard contemplated by the Commission in Order No. 779.[20] The Commission approved Reliability Standard TPL-007-1 in Order No. 830, issued on September 22, 2016.[21] In its Order, the Commission directed NERC to revise the TPL-007 standard as follows:

- revise the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data;[22]
- revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally and efficient alternative, when conducting thermal impact assessments;[23]
- revise the standard to require entities to collect geomagnetically induced current monitoring and magnetometer data as necessary to enable model validation and situational awareness;[24] and

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20 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events*, Docket No. RM15-11-000 (Jan. 21, 2015); *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013), *reh'g denied*, 144 FERC ¶ 61,113 (2013) (directing the development of Reliability Standards to address GMDs in two stages).

21 *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215 (2016) at P 1 ("Order No. 830").

22 *Id.* at P 44.

23 *Id.* at P 65.

24 *Id.* at P 88.

- revise requirements for Corrective Action Plans to include: (i) a one-year deadline for the development of any necessary Corrective Action Plans; (ii) a two-year deadline for the implementation of non-hardware mitigation; and (iii) a four-year deadline for the implementation of hardware mitigation.[25]

In addition to these standard-modification directives, the Commission directed NERC to undertake certain activities intended to enhance knowledge of GMDs and their potential impacts on reliability.[26]

2. <u>Reliability Standard TPL-007-2</u>

On January 22, 2018, NERC submitted Reliability Standard TPL-007-2 for Commission approval. Reliability Standard TPL-007-2 was developed in response to the Commission's directives in Order No. 830. The standard added new requirements for GMD Vulnerability Assessments and thermal impact assessments to be performed based on the supplemental GMD event, a second defined event that accounts for localized peak effects of GMDs and which was not based on spatially-averaged data. Reliability Standard TPL-007-2 included the deadlines specified by the Commission in Order No. 830 for the development and completion of any necessary Corrective Action Plans to address system performance issues resulting from the benchmark GMD event. Additionally, Reliability Standard TPL-007-2 contained new requirements for obtaining GIC monitor and magnetometer data.

The Commission approved Reliability Standard TPL-007-2 in Order No. 851, issued November 15, 2018.[27] In approving the standard, the Commission found that it represented an

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[25] *Id.* at PP 101-102.

[26] *See* Order No. 830 at P 77 (directing NERC to submit a work plan describing how NERC would research specific GMD-related topics identified by the Commission and other topics at NERC's discretion) and PP 89, 93 (directing NERC to collect GIC and magnetometer data pursuant to Section 1600 of the NERC Rules of Procedure and to make the information available). The Commission accepted NERC's revised GMD research work plan in Order No. 851. *See* Order No. 851 at P 65. NERC provides periodic updates to the Commission regarding work performed under this plan in Docket No. RM15-11-003.

[27] *Geomagnetic Disturbance Reliability Standard*; *Reliability Standard for Transmission Planned Performance for Geomagnetic Disturbance Events,* Order No. 851, 165 FERC 61,124 (2018).

improvement over TPL-007-1 and complied with several of the Commission's Order No. 830 directives. The Commission, however, directed NERC to develop and submit two sets of modifications to the standard relating to requirements for Corrective Action Plans.

First, the Commission noted that Reliability Standard TPL-007-2 required applicable entities to assess supplemental GMD event vulnerabilities, but did not require entities to develop formal Corrective Action Plans to address those vulnerabilities. The Commission stated that it saw "no basis, technical or otherwise, for not requiring corrective action plans for assessed supplemental GMD event vulnerabilities while requiring corrective action plans for assessed benchmark GMD event vulnerabilities consistent with the Commission's directions in Order Nos. 779 and 830."[28] The Commission therefore directed NERC to revise the standard to require Corrective Action Plans for assessed supplemental GMD vulnerabilities.[29]

Second, the Commission noted that Reliability Standard TPL-007-2, Requirement R7.4 would allow applicable entities, "under certain conditions, to extend corrective action plan implementation deadlines without prior approval."[30] The Commission stated, "Based on our consideration of the record, we believe that the case-by-case review process contemplated by Order No. 830 is the appropriate means for considering extension requests. Accordingly… we direct that NERC develop modifications to Reliability Standard TPL-007-2 to replace the time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis."[31]

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28 *Id.* at P 48.
29 *Id.*; *see also* Order No. 851 at PP 29 and 39.
30 *Id.* at P 54.
31 *Id.* at P 54.

The Commission directed NERC to submit these modifications within 12 months of the effective date of Reliability Standard TPL-007-2,[32] or by July 1, 2020. The Commission also directed NERC to prepare and submit a report addressing how often and why entities are exceeding Corrective Action Plan deadlines as well as the disposition of extension requests.[33] The Commission directed that this report be submitted within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2.[34]

3. <u>Reliability Standard TPL-007-3</u>

On February 21, 2019, NERC provided an informational notice to the Commission regarding Reliability Standard TPL-007-3.[35] Reliability Standard TPL-007-3 added a regional Variance option for Canadian jurisdictions; no changes were made to any requirement or compliance element that would be mandatory and enforceable in the United States. To provide for consistency in standard versions used throughout North America, NERC transitioned all U.S.-based entities to Reliability Standard TPL-007-3 on July 1, 2019. All phased-in compliance dates for U.S.-based entities were carried forward unchanged from the Commission-approved TPL-007-2 implementation plan.

4. <u>Project 2019-01 Modifications to TPL-007-3</u>

In February 2019, NERC initiated Project 2019-01 Modifications to TPL-007-3 to address the Commission's directives in Order No. 851. Following one 45-day formal comment period and initial ballot, proposed Reliability Standard TPL-007-4 was posted for a 10-day final ballot from November 13, 2019 through November 22, 2019. The proposed standard received a 78.95 percent

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32 *Id.* at P 4.
33 *Id.* at P 30.
34 *Id*.
35 Informational Filing regarding Reliability Standard TPL-007-3, Docket No. RM18-8-000 (Feb. 21, 2019).

approval rating, with 94.52 percent quorum. The NERC Board of Trustees adopted the proposed standard on February 6, 2020.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in **Exhibits E** and **H,** proposed Reliability Standard TPL-007-4 addresses the Commission's directives from Order No. 851, satisfies the Commission's criteria in Order No. 672, and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC respectfully requests that the Commission approve the proposed standard and related elements.

The purpose of proposed Reliability Standard TPL-007-4, which remains unchanged from prior versions of the standard, is to "[e]stablish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events." The applicability of the proposed standard also remains unchanged from prior versions: the proposed standard would continue to apply to: (1) Planning Coordinators and Transmission Planners whose planning areas have a Facility that includes a power transformer with a high side, wye-grounded winding with terminal voltage greater than 200 kV;[36] and (2) Transmission Owners and Generator Owners that own a Facility that includes such equipment.

Consistent with the Commission's directives in Order No. 851, proposed Reliability Standard TPL-007-4 reflects two sets of revisions related to requirements for Corrective Action Plans. First, proposed Reliability Standard TPL-007-4 adds a new Requirement R11 that would require an applicable entity to develop and implement a Corrective Action Plan if it determines that its system would experience performance issues from the supplemental GMD event. Second, proposed Reliability Standard TPL-007-4 revises Requirement R7 so that an applicable entity

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[36] A power transformer with a "high side wye-grounded winding" refers to a power transformer with windings on the high voltage side that are connected in a wye configuration and have a grounded neutral connection.

would be required to submit to its Compliance Enforcement Authority any request to extend a Corrective Action Plan deadline from the two and four years provided in the standard for non-hardware and hardware mitigation, respectively. NERC and Regional Entity staff would then consider each extension request on a case-by-case basis. The revisions, and how they address the Commission's directives from Order No. 851, are discussed in detail in the following sections.

A. Corrective Action Plans to Address Vulnerabilities Identified through Supplemental GMD Vulnerability Assessments

Currently effective Reliability Standard TPL-007-3 Requirement R8 requires entities to perform a supplemental GMD Vulnerability Assessment at least once every 60 calendar months. Consistent with the Commission's directive in Order No. 851,[37] proposed Reliability Standard TPL-007-4 would require an applicable entity to develop a Corrective Action Plan if it determines, through this assessment, that its system would experience performance issues from the supplemental GMD event.

Proposed Reliability Standard TPL-007-4 addresses the Commission's Order No. 851 directive by striking, in its entirety, Requirement R8.3 of the currently effective standard:

> **8.3.** If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

In its place, a new Requirement, R11, is proposed.[38] Proposed Requirement R11 mirrors Requirement R7, which relates to Corrective Action Plans developed to address issues identified through benchmark GMD Vulnerability Assessments. Proposed Requirement R11 provides as follows:

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37 *See* Order No. 851 at PP 29, 39.

38 As shown in **Exhibit A**, currently effective Requirements R11 and R12 would become Requirements R12 and R13.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Proposed Requirement R11 is intended to provide the same content, notification, and deadline requirements for Corrective Action Plans developed in response to the supplemental GMD Vulnerability Assessment that are required for Corrective Action Plans developed in response to the benchmark GMD Vulnerability Assessment. This includes the same provisions for seeking extensions of Corrective Action Plan deadlines. Proposed Requirement R11 Parts 11.3 and 11.4 therefore mirror the proposed revisions to Requirement R7 Parts 7.3 and 7.4, which are discussed more fully below.

B. Corrective Action Plan Deadline Extensions

Currently effective Reliability Standard TPL-007-3 Requirement R7 Part 7.3 provides that an entity shall include in its Corrective Action Plan a timetable for implementing selected mitigation actions that: (i) specifies implementation of non-hardware mitigation, if any, within two years of development of the Corrective Action Plan; and (ii) specifies implementation of hardware mitigation, if any, within four years of development of the Corrective Action Plan. Requirement R7 Part 7.4 specifies the steps that the entity must follow should situations beyond the control of the entity prevent implementation within that timetable. Consistent with the Commission's directive in Order No. 851,[39] proposed Reliability Standard TPL-007-4 Requirement R7 Part 7.4

[39] Order No. 851 at P 54.

would no longer allow entities to extend the two and four-year implementation deadlines without prior approval. Instead, the entity would be required to submit a detailed request for extension to its Compliance Enforcement Authority. Such extensions would then be considered, prospectively, on a case-by-case basis.

Proposed Reliability Standard TPL-007-4 addresses the Commission's directive by revising Requirement R7 Parts 7.3 and 7.4 of the currently effective standard as follows:

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

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7.3. Include a timetable, subject to ~~revision by the responsible entity in~~ <u>approval for any extension sought under</u> Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be ~~revised if situations beyond~~ <u>submitted to</u> the ~~control~~ <u>Compliance Enforcement Authority (CEA) with a request for extension</u> of <u>time if</u> the responsible entity ~~determined in Requirement R1 prevent implementation of~~ <u>is unable to implement</u> the CAP within the timetable ~~for implementation~~ provided in Part 7.3. The ~~revised~~ <u>submitted</u> CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 <u>and how those circumstances are beyond the control of the responsible entity</u>;

~~**7.4.2.** Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~

~~7.4.3.~~7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable~~,~~; and ~~the updated timetable for implementing the selected actions.~~

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

As noted in the previous section, these revisions are also reflected in new Requirement R11 Parts 11.3 and 11.4 pertaining to Corrective Action Plans for the supplemental GMD Vulnerability Assessment.

As with currently effective Reliability Standard TPL-007-3, proposed Reliability Standard TPL-007-4 Requirement R7 Part 7.4 would continue to require entities to explain how the circumstances for the implementation delay are due to factors outside of the entity's control. Such circumstances could include, but are not limited to, delays resulting from: (i) regulatory or legal processes, such as permitting; (ii) stakeholder processes required by tariff, (iii) equipment lead times; or (iv) inability to acquire necessary right-of-way. Proposed Reliability Standard TPL-007-4 Requirement R7 Part 7.4 would also continue to require the entity to include revisions to mitigation actions and an updated timetable for implementation. The notable difference from the currently effective standard to the proposed standard is that an applicable entity may no longer extend an implementation deadline on its own; rather, it would be required to submit a request for a deadline extension to its Compliance Enforcement Authority.

While proposed TPL-007-4 properly focuses on the responsibilities of applicable entities, NERC is mindful of the Commission's expectation in Order No. 851 that the process for considering such extensions "will be timely and efficient such that applicable entities will receive prompt responses" after submitting their requests.[40] To this end, NERC Compliance Assurance

[40] Order No. 851 at PP 55.

staff has developed a draft process document to address how NERC and Regional Entity Compliance Monitoring and Enforcement staff will jointly review requests for extensions to TPL-007-4 Corrective Action Plans. The purpose of this process document is to promote a timely, structured, and consistent approach to extension request submittals and processing.[41] NERC Compliance Assurance staff will maintain this process document under existing ERO Enterprise processes and will review and update it as needed. As directed by the Commission in Order No. 851, NERC will prepare and submit a report addressing how often and why applicable entities are exceeding Corrective Action Plan deadlines and the disposition of extension requests within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-4.[42]

C. Enforceability of Proposed Reliability Standard TPL-007-4

Proposed Reliability Standard TPL-007-4 includes measures in support of each requirement to ensure that requirements are enforced in a clear, consistent, non-preferential manner, without prejudice to any party. The proposed standard also includes VRFs and VSLs for each requirement, which are used to help determine appropriate sanctions if an applicable entity violates a requirement. VRFs assess the impact to reliability of violating a specific requirement, while VSLs provide guidance on the way that NERC will enforce requirements.

The proposed standard includes VRFs and VSLs for Requirements R1 through R10, R12 (formerly R11), and R13 (formerly R12) that are substantively the same as those which were

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[41] Two drafts of the draft process document, titled the TPL-007-4 Corrective Action Plan Extension Review Process, were posted for information alongside the draft TPL-007-4 standard. See Ex. F (Summary of Development and Complete Record of Development) at items 15 and 31.

[42] Order No. 851 at P 25. As noted in Section V below, the implementation plan for proposed Reliability Standard TPL-007-4 carries forward the existing phased-in compliance schedule established by the TPL-007-2 implementation plan.

approved by the Commission in Order Nos. 830 and 851.[43] The proposed VRF assignment for new Requirement R11 is High, to promote consistency among the standard's requirements for Corrective Action Plans. Similarly, the proposed VSL assignment for new Requirement R11 mirrors the existing VSLs for Requirement R7. As discussed in **Exhibit C**, these VRFs and VSLs comport with NERC and Commission guidelines related to their assignment.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve NERC's proposed implementation plan, attached to this petition as **Exhibit B**. Under this plan, proposed Reliability Standard TPL-007-4 would become effective on the first day of the first calendar quarter that is six months after Commission approval. NERC requests retirement of Reliability Standard TPL-007-3 immediately prior to the effective date of TPL-007-4.

The proposed TPL-007-4 implementation plan integrates the new and revised Corrective Action Plan requirements in proposed Reliability Standard TPL-007-4 with the existing phased-in compliance date timeframe under the TPL-007-3 implementation plan.[44] Assuming the Commission's order approving the proposed standard becomes effective before June 2023, applicable entities would be required to develop any required Corrective Action Plans under new Requirement R11 (supplemental GMD Vulnerability Assessment) by the same date presently required for Corrective Action Plans under existing Requirement R7 (benchmark GMD Vulnerability Assessment).

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[43] The VSL for Requirement R7 was modified slightly to more closely reflect the language of the Requirement. The VSL for Requirement R8 was modified to eliminate reference to the stricken subpart.

[44] For U.S.-based entities, the TPL-007-3 implementation plan carried forward the phased-in compliance dates approved by the Commission in the TPL-007-2 implementation plan.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve proposed Reliability Standard TPL-007-4 and related elements, the proposed implementation plan, and the retirement of currently effective Reliability Standard TPL-007-3 as discussed herein.

Respectfully submitted,

/s/ Lauren A. Perotti

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Exhibit A1

Proposed Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Operations (Clean)

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-4
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

   4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-4.
6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R12 and R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event				
Steady State: a. Voltage collapse, Cascading and uncontrolled islanding shall not occur. b. Generation loss is acceptable as a consequence of the steady state planning GMD events. c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.				
Category	**Initial Condition**	**Event**	**Interruption of Firm Transmission Service Allowed**	**Load Loss Allowed**
Benchmark GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes
Table 1: Steady State Performance Footnotes				
1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. 2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1. 3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.				

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to “Attachment 1” in the standard with “Attachment 1 or Attachment 1-CAN.”

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity’s System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	February 6, 2020	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \ (V/km) \tag{1}$$

$$E_{peak} = 12 \times \alpha \times \beta_s \ (V/km) \tag{2}$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \tag{3}$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

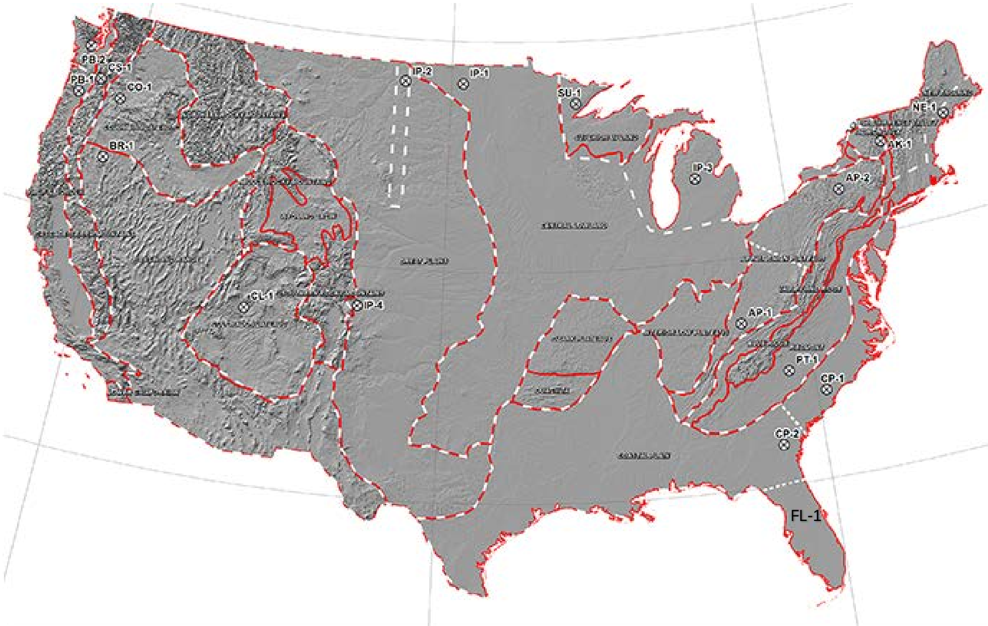

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

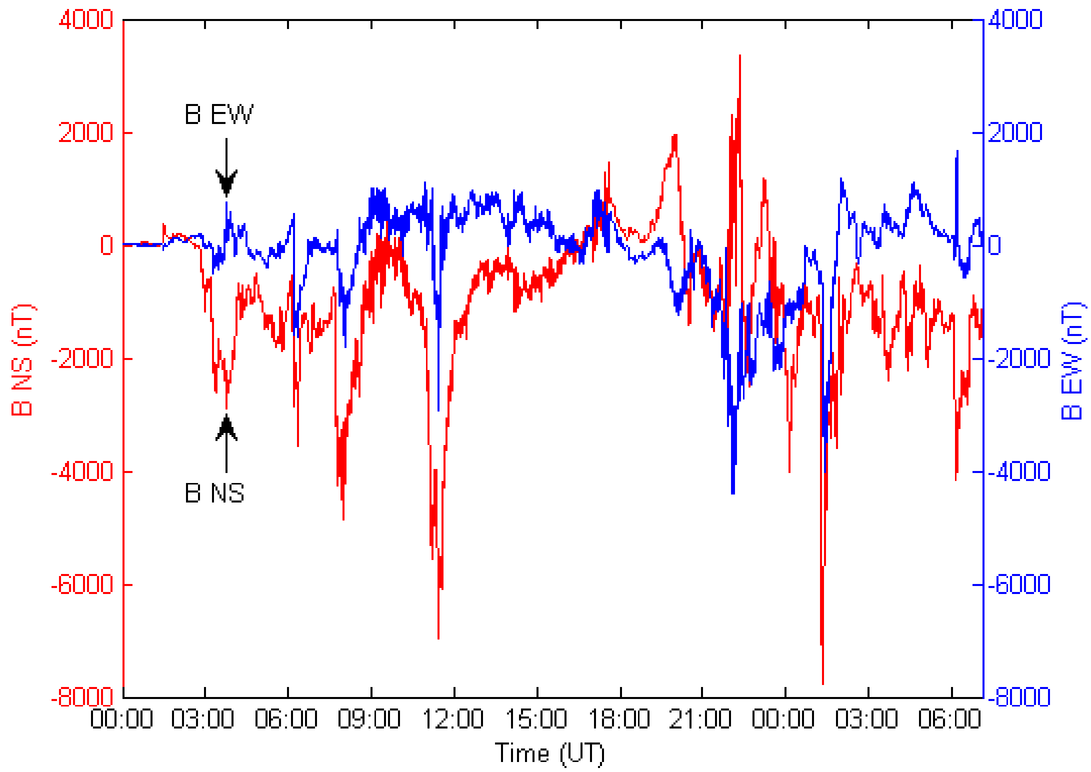

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

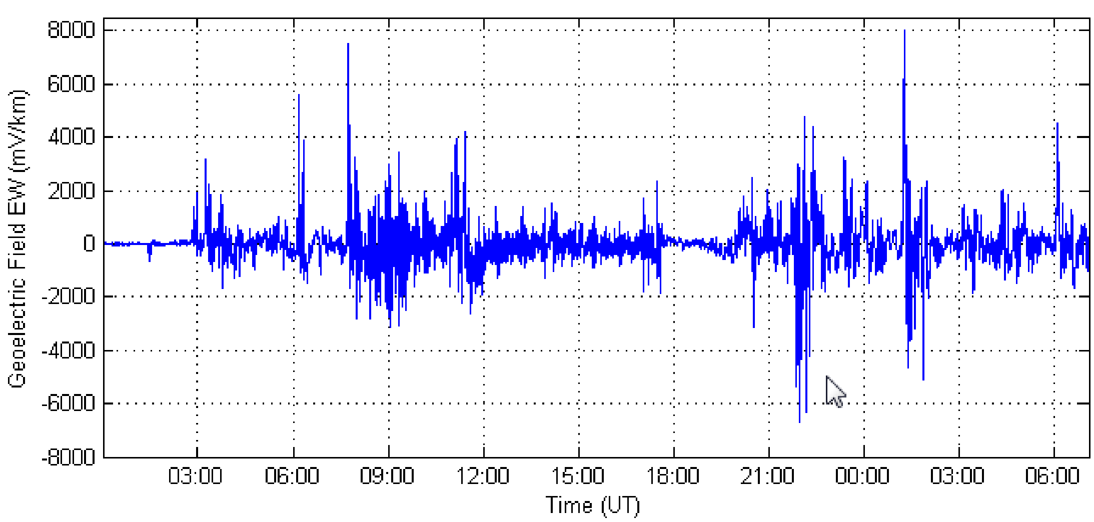

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

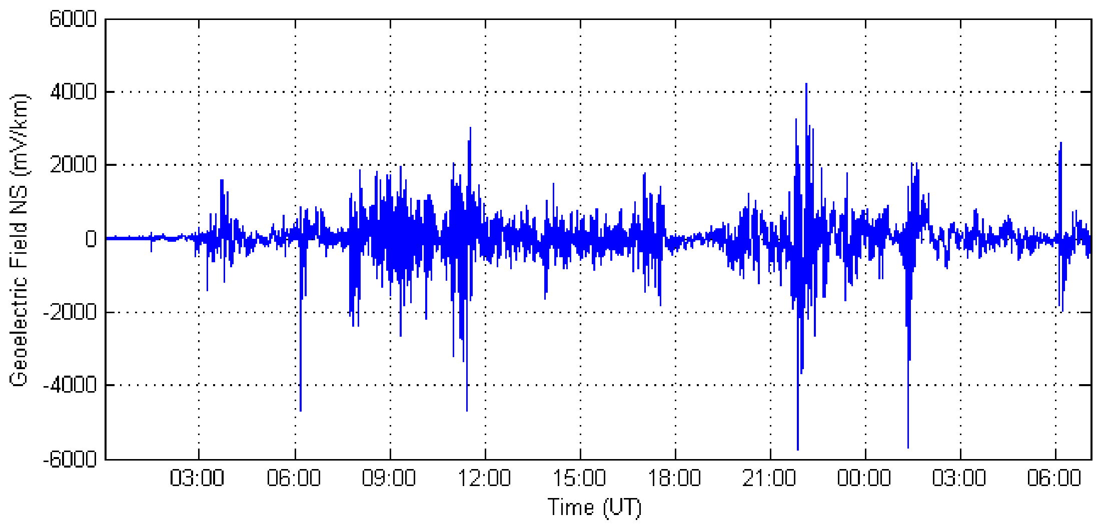

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

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[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

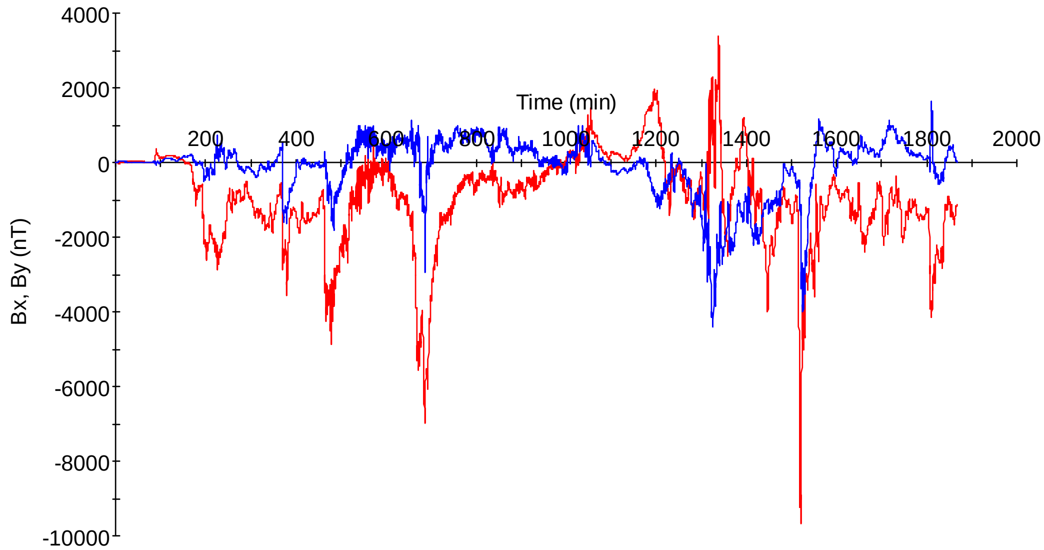

Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

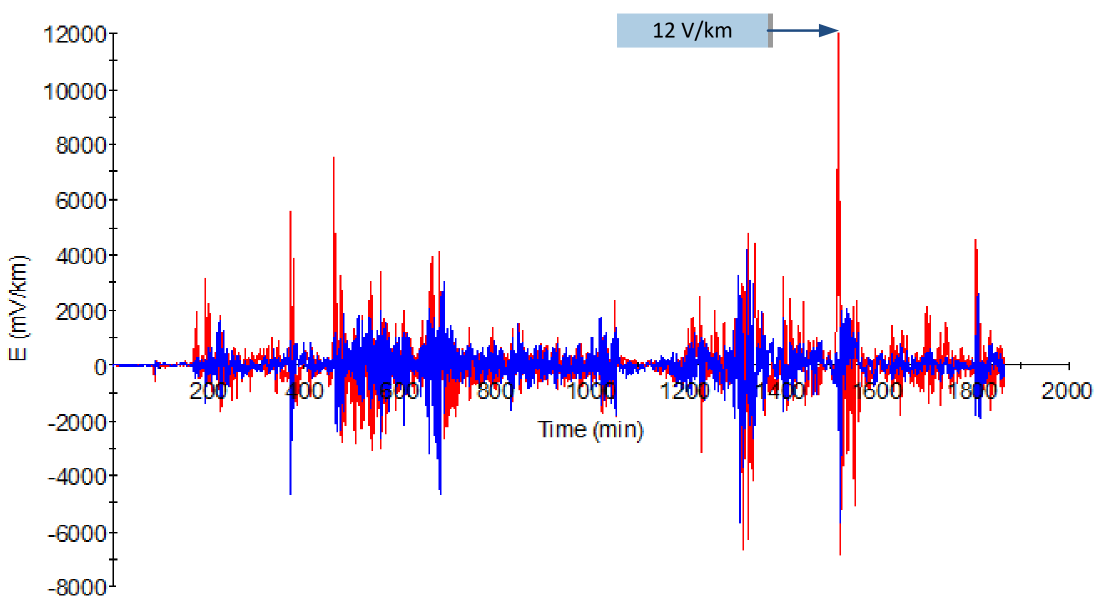

Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A2

Proposed Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Operations (Redline to TPL-007-3)

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~3~~4

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

   4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-~~3~~4.

6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

~~The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of that in TPL-007-2.~~

~~C.~~B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~revision by the responsible entity in~~approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be ~~revised if situations beyond~~submitted to the ~~control~~Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity ~~determined in Requirement R1 prevent implementation of~~is unable to implement the CAP within the timetable ~~for implementation~~ provided in Part 7.3. The ~~revised~~submitted CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

~~**7.4.2.** Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~

~~**7.4.3.**~~**7.4.2.** Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable~~,~~; and ~~the updated timetable for implementing the selected actions.~~

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the ~~results~~CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it ~~has revised its CAP~~submitted a request for extension to the CEA if ~~situations beyond~~ the responsible ~~entity's control prevent implementation of~~entity is unable to implement the CAP within the timetable ~~specified.~~provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

~~**8.3.** If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.~~

~~8.4.~~8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

~~8.4.1.~~8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

~~R11.~~**R12.** Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M11.~~M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement ~~R11~~R12.

~~R12.~~R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M12.~~M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement ~~R12~~R13.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements ~~R11~~R12 and ~~R12~~R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		months since the last benchmark GMD Vulnerability Assessment.	months since the last benchmark GMD Vulnerability Assessment.	benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not ~~have~~develop a Corrective Action Plan as required by Requirement R7.
R8.	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;~~ ~~OR~~ The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~two~~one of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~three~~two of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~four~~three of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1	for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1;	for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	OR The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R11~~R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
~~R12~~R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

~~E.~~D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

~~All~~This variance replaces all references to "Attachment 1" in the standard ~~are replaced~~ with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

~~F.~~E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	February 6, 2020	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \, (V/km) \tag{1}$$

$$E_{peak} = 12 \times \alpha \times \beta_s \, (V/km) \tag{2}$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \tag{3}$$

where, L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the ~~planning~~responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \tag{4}$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \tag{5}$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

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[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

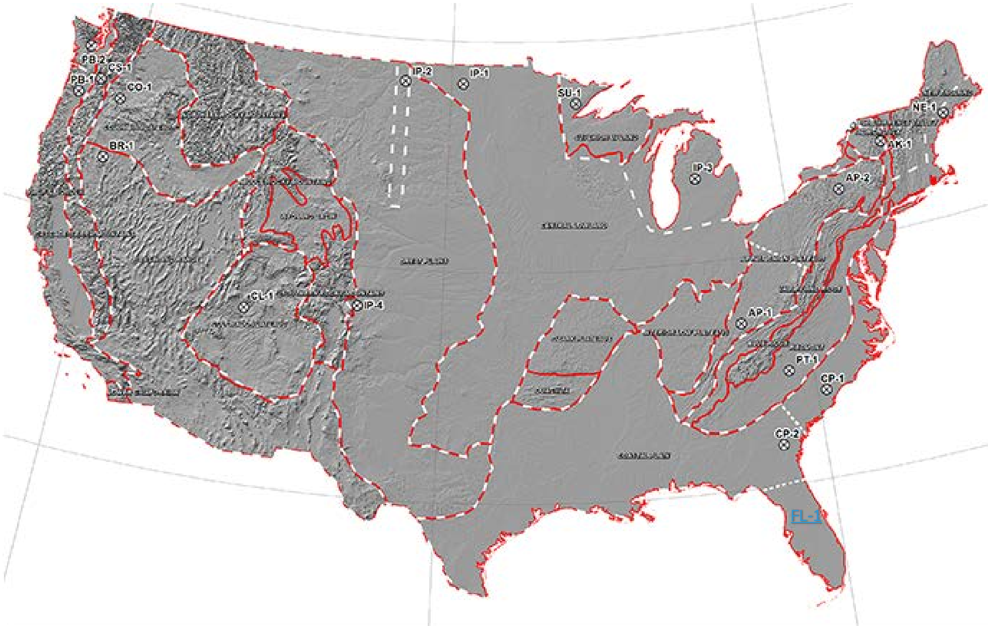

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors

Earth model	Scaling Factor Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

~~Rationale: Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.~~

~~The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated based on the earth model published on the USGS public website.~~

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

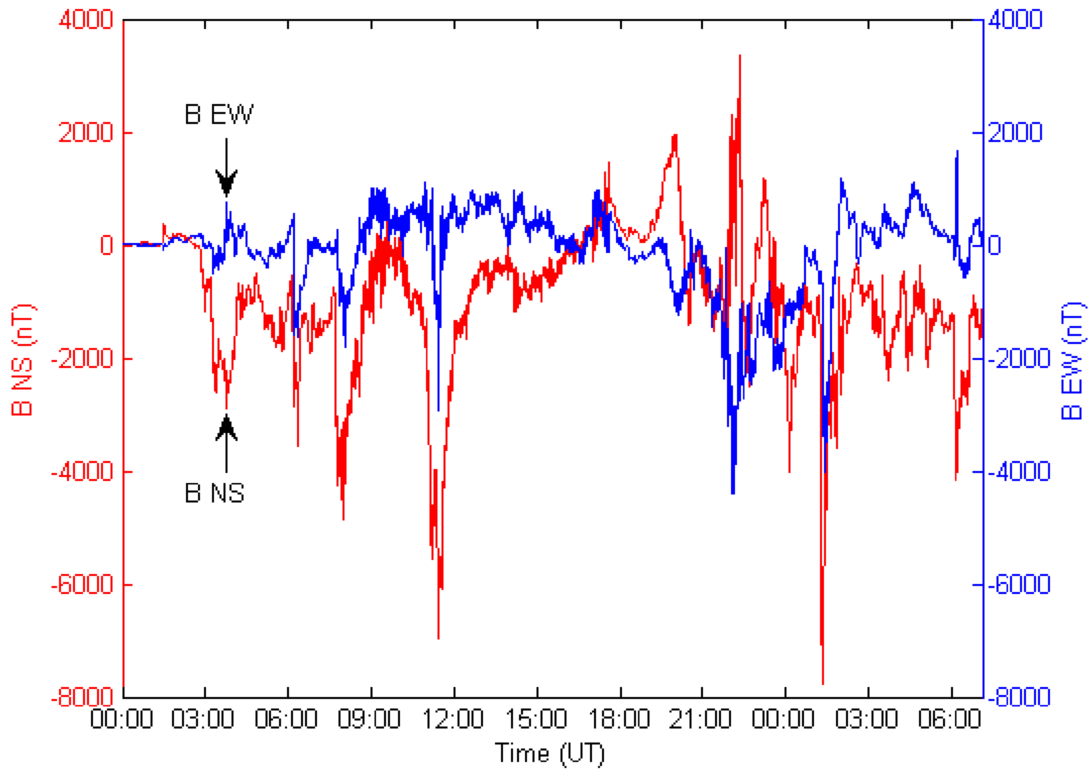

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

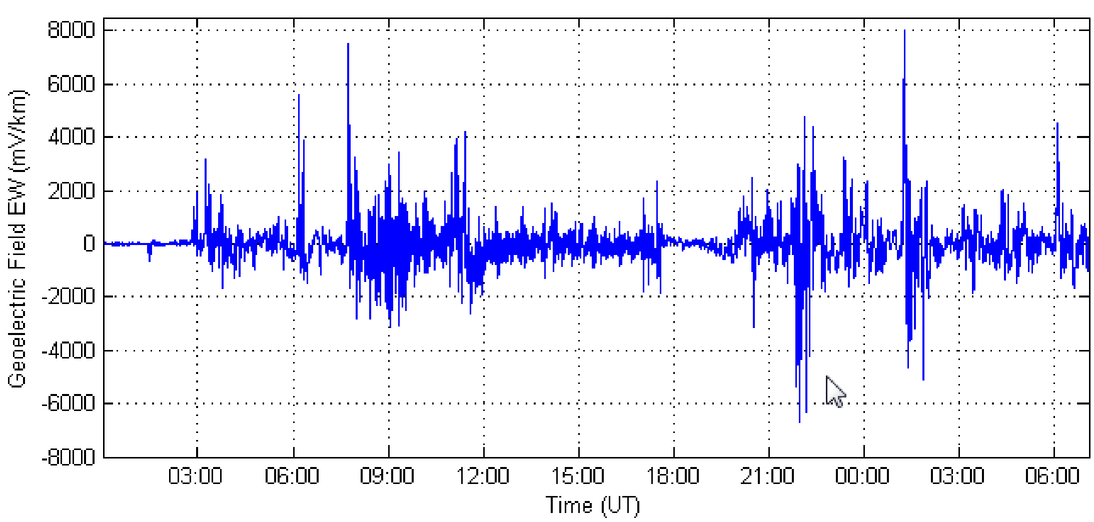

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

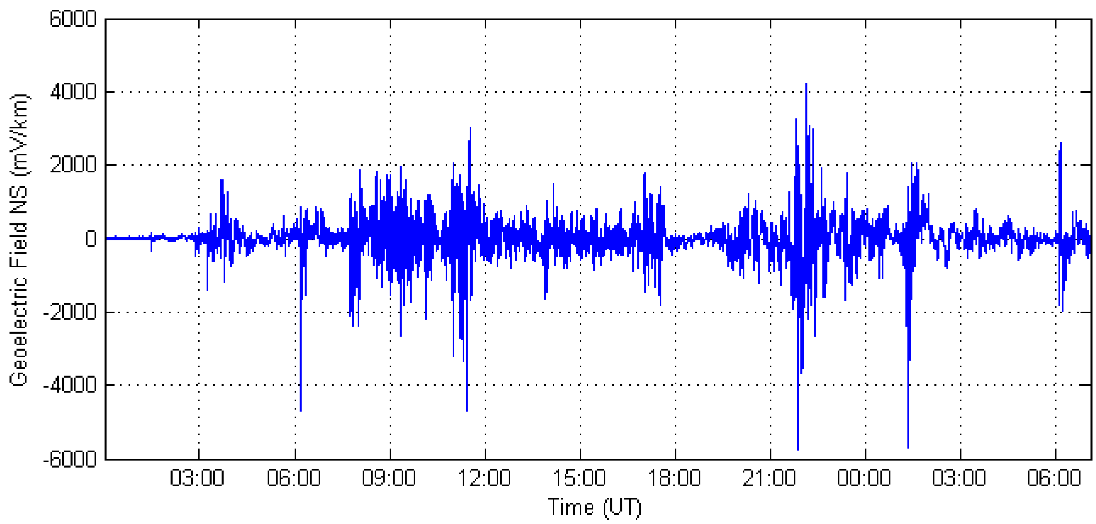

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.**[10]** To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

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[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

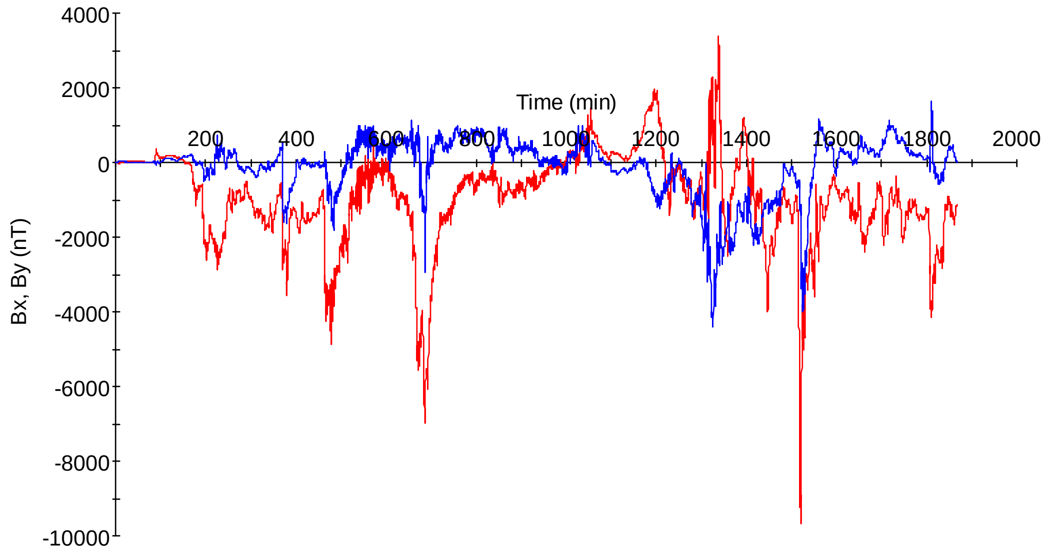


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

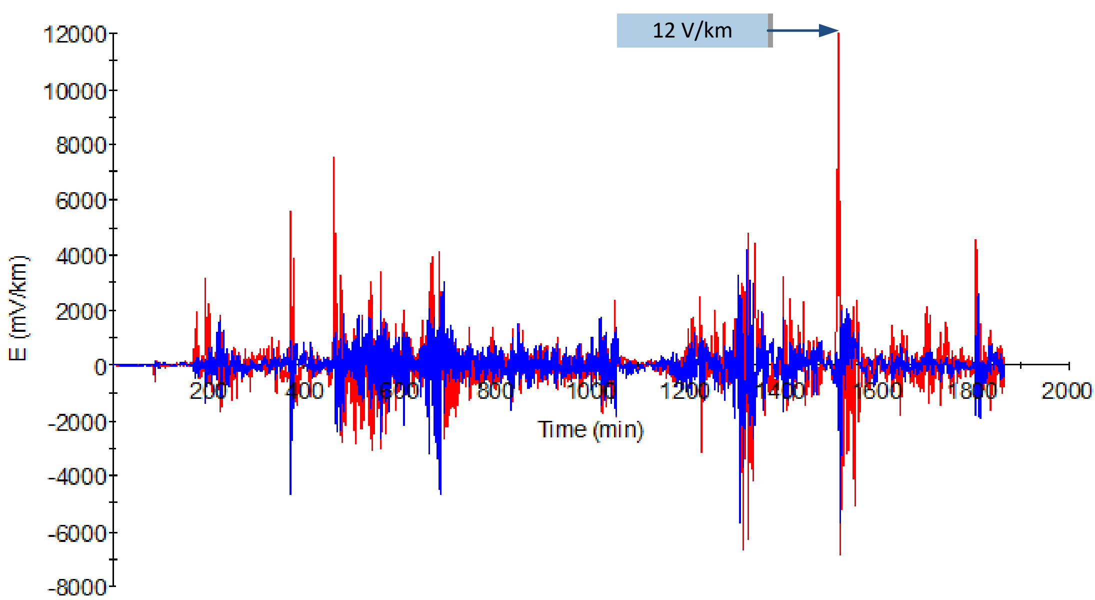


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).~~[1]~~[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

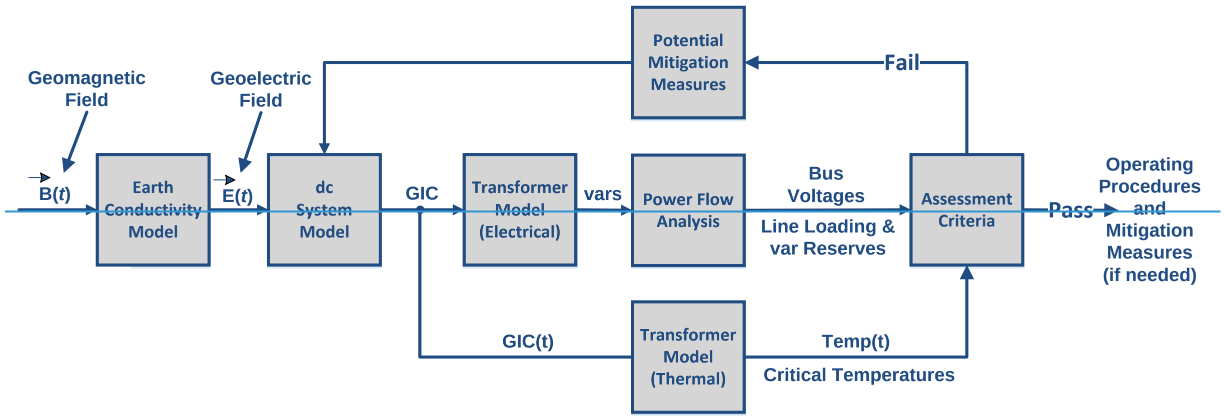
~~[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.~~

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

~~Guidelines and Technical Basis~~

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



~~The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.~~

~~Benchmark GMD Event (Attachment 1)~~

~~The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016[11] white paper includes the event description, analysis, and example calculations.~~

~~Supplemental GMD Event (Attachment 1)~~

~~The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017[12] white paper includes the event description and analysis.~~

~~Requirement R2~~

~~A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*, December 2013.[13]~~

~~Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the~~

[11] ~~http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.~~
[12] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
[13] ~~http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.~~

~~conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.~~

~~Requirement R4~~

~~The *Geomagnetic Disturbance Planning Guide*,[14] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~Requirement R5~~

~~The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.~~

~~GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time-series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the *Transformer Thermal Impact Assessment White Paper*,[15] October 2017.~~

~~The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R6~~

~~The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed*~~

~~[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~[15] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~*Implementation Guidance*[16] for this requirement. This ERO-Endorsed document is posted on the NERC Compliance Guidance[17] webpage.~~

~~Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[18] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.~~

~~The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R7~~

~~Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*,[19] December 2013. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[20] February 2012.~~

~~Requirement R8~~

~~The *Geomagnetic Disturbance Planning Guide*,[21] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.~~

~~Requirement R9~~

~~The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~[16] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~

~~[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx.~~

~~[18] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~[19] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~[20] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~

~~[21] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.~~

~~GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.~~

~~The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R10~~

~~The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[22] discussed in the Requirement R6 section above. A later version of the *Transformer Thermal Impact Assessment White Paper*,[23] October 2017, has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment.~~

~~Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[24] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.~~

~~The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R11~~

~~Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[25] February 2012. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful for model validation and situational awareness.~~

[22] ~~http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~

[23] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

[24] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

[25] ~~http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~

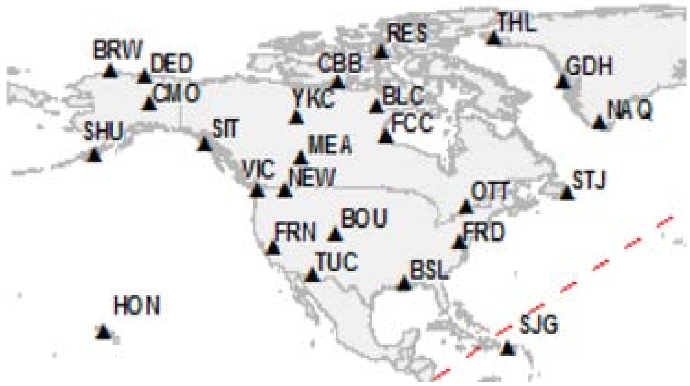
~~Responsible entities consider the following in developing a process for obtaining GIC monitor data:~~

- ~~**Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.~~
- ~~**Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.~~
- ~~**Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.~~
- ~~**Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.~~
- ~~**Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.~~
- ~~**Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.~~
- ~~**Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).~~

~~Requirement R12~~

~~Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:~~

- ~~Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:~~[26]



- ~~Research institutions and academic universities;~~
- ~~Entities with installed magnetometers.~~

~~Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012.~~[27]

[26] ~~http://www.intermagnet.org/index-eng.php.~~
[27] ~~http://www.intermagnet.org/publications/intermag_4-6.pdf.~~

~~Rationale~~

~~During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].~~

~~Rationale for Applicability:~~

~~Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.~~

~~Terminal voltage describes line-to-line voltage.~~

~~Rationale for R1:~~

~~In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).~~

~~Rationale for R2:~~

~~A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System*,[28] December 2013, developed by the NERC GMD Task Force.~~

~~The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.~~

~~The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.~~

~~The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.~~

~~The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (Docket No. RM12-1-000). NERC guidelines require consistency among Reliability Standards.~~

~~[28] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.~~

~~**Rationale for R3:**~~

~~Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.~~

~~**Rationale for R4:**~~

~~The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.~~

~~At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.~~

~~Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.~~

~~The *Geomagnetic Disturbance Planning Guide*,[29] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~**Rationale for R5:**~~

~~This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.~~

~~GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*,[30] October 2017.~~

~~A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but~~

~~[29] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~[30] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.~~

~~The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~Rationale for R6:~~

~~The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[31] October 2017.~~

~~The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper*,[32] October 2017.~~

~~Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.~~

~~Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.~~

~~The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~Rationale for R7:~~

~~The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P 102):~~

- ~~Two years for non-hardware mitigation; and~~
- ~~Four years for hardware mitigation.~~

~~The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part~~

~~[31] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
~~[32] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~7.3. Examples of situations beyond the control of the of the responsible entity (see Section 7.4) include, but are not limited to:~~

- ~~Delays resulting from regulatory/legal processes, such as permitting;~~
- ~~Delays resulting from stakeholder processes required by tariff;~~
- ~~Delays resulting from equipment lead times; or~~

~~Delays resulting from the inability to acquire necessary Right-of-Way.~~

~~Rationale for Table 3:~~

~~Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74. [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]~~

~~Rationale for R8 – R10:~~

~~The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P 44, P 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.~~

~~Rationale for R11 – R12:~~

~~The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88; P. 90-92). GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R11 and R12, respectively. See the Guidelines and Technical Basis section of this standard for technical information.~~

~~The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.~~

~~The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:~~

- ~~Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;~~
- ~~Installed magnetometers; and~~
- ~~Commercial or third-party sources of geomagnetic field data.~~

~~Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.~~

Exhibit B

Implementation Plan

Implementation Plan

Project 2019-01 Modifications to TPL-007-3

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. No continent-wide requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

General Considerations

This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard TPL-007-4

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1, R2, R5, and R9

Entities shall be required to comply with Requirements R1, R2, R5, and R9 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R12 and R13

Entities shall not be required to comply with Requirements R12 and R13 until the later of: (i) July 1, 2021; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the later of: (i) January 1, 2022; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R3, R4, and R8

Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7

Entities shall not be required to comply with Requirement R7 until the later of: (i) January 1, 2024; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R11
Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.

Retirement Date

Standard TPL-007-3
Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

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Exhibit C

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justification

Project 2019-01 Modifications to TPL-007-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification for TPL-007-4, Requirement R1
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R1
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R2
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R2
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R3
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R3
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R4
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R4
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R5
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R5
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R6
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R6
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R7
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R7
The VSL did not substantively change from the TPL-007-3 Reliability Standard or FERC-approved TPL-007-2 Reliability Standard. In the Severe VSL, the word “have” was replaced with “develop” to more closely reflect the language of the Requirement.

VRF Justification for TPL-007-4, Requirement R8
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R8
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R9
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R9
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R10
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R10
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VSL Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSLs for TPL-007-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications for TPL-007-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs retain the VSLs from the TPL-007-3 Reliability Standard, approved by FERC in TPL-007-2, with the exception of removing one part of the lower VSL to reflect the removal of subpart 8.3 in proposed TPL-007-4. As a result, the proposed VSLs do not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VSLs for TPL-007-4, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance. Further, the VSLs are consistent with those assigned for Requirement R7, pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is being proposed for this requirement.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The proposed VRF is consistent among other FERC approved VRFs within the standard, specifically Requirement R7 pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a supplemental GMD Vulnerability Assessment could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

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Exhibit D

Technical Rationale

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Transmission System Planned Performance for Geomagnetic Disturbance Events

Technical Rationale and Justification for Reliability Standard TPL-007-4

November 2019

RELIABILITY | RESILIENCE | SECURITY




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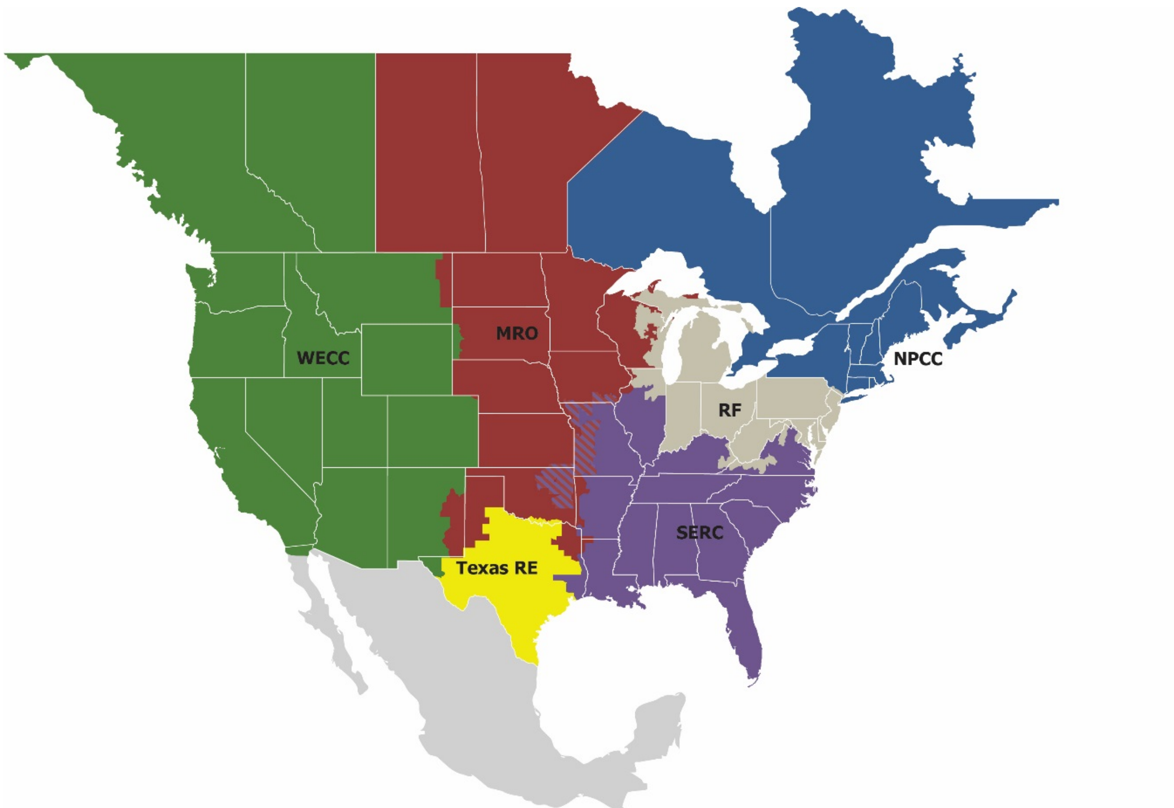
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. It also contains information on the standard drafting team's intent in drafting the requirements. This document, the Technical Rationale and Justification for TPL-007-4, is not a Reliability Standard and should not be considered mandatory and enforceable.

The first version of the standard, TPL-007-1, approved by FERC in Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect Canadian-specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version of the standard, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 with a process through which extensions of time are considered on a case-by-case basis (P 54).

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process. Figure 1 provides an overall view of the GMD Vulnerability Assessment process:

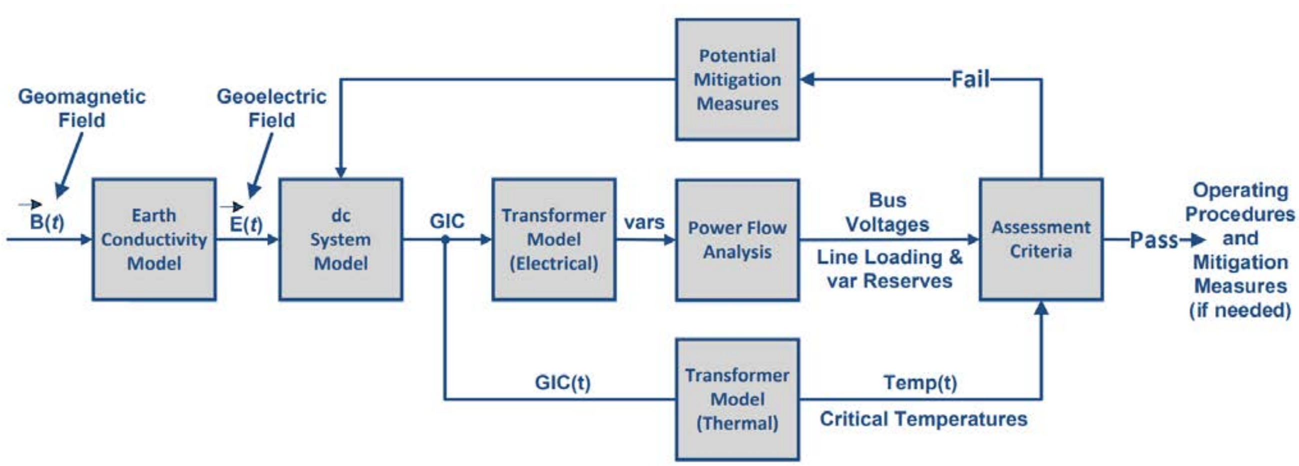


Figure 1. GMD Vulnerability Assessment Process.

General Considerations

Rationale for Applicability

Reliability Standard TPL-007-4 is applicable to Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these types of transformers are not included in the applicability for this standard. Terminal voltage describes line-to-line voltage.

Benchmark GMD Event (TPL-007-4 Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016 [4], includes the event description, analysis, and example calculations.

Supplemental GMD Event (TPL-007-4 Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017 [5], includes the event description and analysis.

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model are provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

System models specified in Requirement R2 are used in conducting steady state power flow analysis, that accounts for the Reactive Power absorption of power transformer(s) due to GIC flow in the System, when performing GMD Vulnerability Assessments. Additional System modeling considerations could include facilities less than 200 kV.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

Requirement R4

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load shall be included in the in the study or studies (see Requirement R4).

Requirement R5

The benchmark thermal impact assessment of transformers, specified in Requirement R6, is based on GIC information for the benchmark GMD Event. This GIC information is determined by the responsible entity through simulation of the GIC System model and shall be provided to the entity responsible for conducting the thermal impact assessment (see Requirement R5). GIC information for the benchmark thermal impact assessment should be provided in accordance with Requirement R5 each time the benchmark GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 75 A per phase, in the benchmark GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the benchmark thermal impact of GIC on transformers in the planning area and shall be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment (see Requirement R5). GIC information should be provided in accordance with Requirement R5 as part of the benchmark GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 5.2 can be used to convert the steady state GIC flows to time-series GIC data for the benchmark transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Requirement R6

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the responsible entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.

Thermal assessments for transformers with a high side, grounded-wye winding greater than 200 kV are required because the damage of these types of transformers may have an effect on the wide-area reliability of the interconnected Transmission System.

Requirement R7

This requirement addresses directives in FERC Order No. 851 to replace the time-extension provision in Requirement R7.4 of TPL-007-2 (and TPL-007-3) with a process through which extensions of time are considered on a case-by-case basis.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Supplemental GMD Vulnerability Assessment

The requirements, R8-R11, address directives in FERC Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (PP 44, 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Requirement R8

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load shall be included in the study or studies (see Requirement R8).

Requirement R9

The supplemental thermal impact assessment of transformers, specified in Requirement R10, is based on GIC information for the supplemental GMD Event. This GIC information is determined by the responsible entity through simulation of the GIC System model and shall be provided to the entity responsible for conducting the thermal impact assessment (see Requirement R9). GIC information for the supplemental thermal impact assessment should be provided in accordance with Requirement R9 each time the supplemental GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 85 A per phase, in the supplemental GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the supplemental thermal impact of GIC on transformers in the planning area and shall be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment (see Requirement R9). GIC information should be provided in accordance with Requirement R9 as part of the supplemental GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 9.2 can be used to convert the steady state GIC flows to time-series GIC data for the supplemental transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [10].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the responsible entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R9.

Thermal assessments for transformers with a high side, grounded-wye winding greater than 200 kV are required because the damage of these types of transformers may have an effect on the wide-area reliability of the interconnected Transmission System.

Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for the assessed supplemental GMD event vulnerabilities.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the Geomagnetic Disturbance Planning Guide, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Requirement R12

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect GIC monitoring data as necessary to enable model validation and situational awareness (PP 88, 90-92).

Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9]. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer and measure dc current flowing through the neutral. Data from GIC monitors is useful for model validation and situational awareness.

The objective of Requirement R12 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Requirement R13

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect magnetometer data as necessary to enable model validation and situational awareness (PP 88, 90-92).

The objective of Requirement R13 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

References

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7. Geomagnetic Disturbance Planning Guide, NERC, Atlanta, GA, December, 2013, https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf
8. Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Thermal_Impact_Assessment_2017_October_Clean.pdf
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10. Screening Criterion for Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Screening_Criterion_Clean_2017_October_Clean.pdf

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Exhibit E

Order No. 672 Criteria for Proposed Reliability Standard TPL-007-4

Exhibit E — Order No. 672 Criteria

<u>Order No. 672 Criteria</u>

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

Proposed Reliability Standard TPL-007-4 addresses the unique risks posed by a high-impact, low-frequency geomagnetic disturbance ("GMD") event on the reliable operation of the Bulk-Power System ("BPS") and is responsive to the Commission's directives in Order No. 851. As with prior versions of the TPL-007 standard, the proposed standard is based on sound scientific and technical principles.

Currently effective Reliability Standard TPL-007-3 requires applicable entities to conduct initial and on-going assessments of the potential impact of two defined GMD events, the

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) ("Order No. 672").

[2] *See* Order No. 672 at P 321 ("The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.").

See Order No. 672 at P 324 ("The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.").

benchmark GMD event and the supplemental GMD event, on BPS equipment and the BPS as a whole. The standard presently requires entities to develop and implement Corrective Action Plans to protect against instability, uncontrolled separation, and cascading failures of the BPS identified through benchmark GMD Vulnerability Assessments. The standard also contains requirements for implementing processes to collect GMD monitoring data.

Proposed Reliability Standard TPL-007-4 improves upon the current version of the standard and addresses the Order No. 851 directives by: (i) requiring entities to develop Corrective Action Plans for vulnerabilities identified through supplemental GMD Vulnerability Assessments;[3] and (ii) requiring entities to seek approval from the ERO of any extensions of time for the completion of Corrective Action Plan items.[4]

2. Proposed Reliability Standards must be applicable only to users, owners, and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[5]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Consistent with currently effective Reliability Standard TPL-007-3, proposed Reliability Standard TPL-007-4 is applicable to: (1) Planning Coordinators with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (2) Transmission Planners with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (3) Transmission Owners that own a Facility or Facilities

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3 *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 851, 165 FERC ¶ 61,124 (2018) at PP 29 and 39.

4 *Id.* at P 54.

5 *See* Order No. 672 at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").

See Order No. 672 at P 325 ("The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.").

that include a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; and (4) Generator Owners that own a Facility or Facilities that include a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.[6] The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[7]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner.[8]

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures

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6 A power transformer with a "high side wye-grounded winding" refers to a power transformer with windings on the high voltage side that are connected in a wye configuration and have a grounded neutral connection.

7 *See* Order No. 672 at P 326 ("The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.").

8 *See* Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

help provide clarity regarding how the requirements will be enforced and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently, but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[9]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to conducting initial and on-going assessments of the potential impact of defined GMD events on BPS equipment and the BPS as a whole and provides entities the flexibility to select appropriate mitigation strategies to address identified vulnerabilities.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[10]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant reliability benefits for the BPS and addresses directives and concerns identified by the Commission in Order

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[9] *See* Order No. 672 at P 328 ("The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.").

[10] *See* Order No. 672 at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See Order No. 672 at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

No. 851. The provisions of the proposed standard raise the level of preparedness by requiring applicable entities to develop Corrective Action Plans to address system performance issues identified through supplemental GMD Vulnerability Assessments. The proposed standard also revises requirements for Corrective Action Plans so that entities would be required to submit any requests to extend Corrective Action Plan deadlines to NERC and the Regional Entities, so that such requests may be considered on a case-by-case basis.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[11]

The proposed Reliability Standard applies consistently throughout North America and does not favor one geographic area or regional model. The proposed standard includes technically-justified scaling factors that allow for entity-specific tailoring of the benchmark and supplemental GMD events. This approach provides for consistent application of the proposed Reliability Standard throughout North America while still accounting for the varying impact GMD events may have on each region.

The proposed Reliability Standard, like the currently effective standard, also contains a regional Variance option for Canadian entities. This Variance accounts for differences in regulatory processes in some Canadian jurisdictions with respect to implementation of Corrective Action Plans. This Variance also provides an option which would allow Canadian entities to

[11] *See* Order No. 672 at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.").

perform assessments using regionally specific information where such information provides a technically justified means to re-define one or more 1-in-100 year GMD planning event(s) within its planning area.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[12]

Proposed Reliability Standard TPL-007-4 has no undue negative effect on competition and does not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standard requires the same performance by each of the applicable entities. The information sharing required by the proposed standard is necessary for reliability and can be accomplished without presenting any market or competition-related concerns.

9. The implementation time for the proposed Reliability Standard is reasonable.[13]

The proposed effective date for proposed Reliability Standard TPL-007-4 is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing, or other relevant capability. The proposed TPL-007-4 implementation plan integrates the new and revised Corrective Action Plan requirements in proposed Reliability Standard TPL-007-4 with the existing phased-in compliance date timeframe

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12 *See* Order No. 672 at P 332 ("As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.").

13 *See* Order No. 672 at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

under the TPL-007-3 implementation plan.[14] Assuming the Commission's order approving the proposed standard becomes effective before June 2023, applicable entities would be required to develop any required Corrective Action Plans under new Requirement R11 (supplemental GMD Vulnerability Assessment) by the same date presently required for Corrective Action Plans under existing Requirement R7 (benchmark GMD Vulnerability Assessment). The proposed implementation plan is attached as **Exhibit B** to this Petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[15]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit F** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

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[14] For U.S.-based entities, the TPL-007-3 implementation plan carried forward the phased-in compliance dates approved by the Commission in the TPL-007-2 implementation plan.

[15] *See* Order No. 672 at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[16]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[17]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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16 *See* Order No. 672 at P 335 ("Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.").

17 *See* Order No. 672 at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Summary of Development History
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard TPL-007-4.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2019-01 Modifications to TPL-007-3 SDT members is included in **Exhibit G**.

II. Standard Development History

A. Standard Authorization Request Development

On February 20, 2019, the Standards Committee authorized posting a Standards Authorization Request ("SAR") as well as the solicitation of nominations for the Project 2019-01 Revisions to TPL-007-3 SDT.[3] The SAR was posted for a 30-day informal comment period from February 25, 2019 through March 26, 2019 and the drafting team nominations were open for the same period. The SAR received 24 sets of responses, including comments from approximately 67 different people from approximately 51 companies, representing 7 industry segments.[4]

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2018).

2 The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

3 NERC, *Minutes – Standards Committee Conference Call* (February 20, 2019), Agenda Item 6, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards_Committee_Meeting_Minutes_%20Approve_March_20_2019.pdf.

4 *Comment Report – Project 2019-01 Modifications to TPL-007-3 SAR*, https://www.nerc.com/pa/Stand/Project201901ModificationstoTPL0073/2019-01_rawcomments_Word_032719.pdf.

B. First Posting – Formal Comment Period and Initial Ballot

An initial draft of proposed Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events was posted for a 45-day formal comment period from July 26, 2019 through September 9, 2019, along with the implementation plan and other supporting documents. There were 66 sets of responses, including comments from approximately 133 different individuals and approximately 98 companies, representing all 10 industry segments.[5] An initial ballot was open for the final ten days of the comment period from August 30, 2019 through September 9, 2019. The proposed standard received 70.84 percent approval with a quarum of 91.44 percent.[6] A simultaneous non-binding poll for the VRFs and VSLs received 71.04 percent support with a quarum of 88.81 percent.[7]

C. Final Ballot

Proposed Reliability Standard TPL-007-4 was posted for a 10-day final ballot period from November 13, 2019 through November 22, 2019. The proposed standard received a 78.95 percent approval rating, with 94.52 percent quorum.[8]

D. Board of Trustees Adoption

On February 6, 2020, the NERC Board of Trustees adopted proposed Reliability Standard TPL-007-4, the Implementation Plan, and the associated VRFs and VSLs.

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5 NERC, *Consideration of Comments — Project 2019-01 Modifications to TPL-007-3*, https://www.nerc.com/pa/Stand/Project201901ModificationstoTPL0073/2019-01_Response%20to%20Comments_Final%20Ballot.pdf.

6 NERC, *Ballot Results — 2019-01 Modifications to TPL-007-3 TPL-007-4 IN 1 ST,* https://sbs.nerc.net/BallotResults/Index/366.

7 NERC, *Ballot Results — 2019-01 Modifications to TPL-007-3 TPL-007-4 Non-binding Poll IN 1 NB*, https://sbs.nerc.net/BallotResults/Index/367.

8 NERC, *Ballot Results — 2019-01 Modifications to TPL-007-3 TPL-007-4 FN 2 ST*, https://sbs.nerc.net/BallotResults/Index/398.

Complete History of Development

Project 2019-01 Modifications to TPL-007-3

Related Files

Status

A 10-day final ballot for **TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events** concluded at **8 p.m. Eastern, Friday, November 22, 2019.**

The ERO CAP Extension Request Review Process was developed by NERC Compliance Assurance staff and was provided for informational purposes only. It was not part of the material being balloted.

Background

The first version of the standard, TPL-007-1, requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with the FERC's directives in Order No. 830. The third version of the standard adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics Background Information. This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Standard(s) Affected – TPL-007-3

Purpose/Industry Need

This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3.

Subscribe to the Project 2019-01 Modifications to TPL-007-3 Observer Distribution List

Select "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify "Project 2019-01 Modifications to TPL-007-3 Observer List" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final **TPL-007-4** **(23)** Clean | Redline to Last Posted **(24)** **(25)** Redline to Last Approved **(26)** Implementation Plan **Supporting Materials** **(27)** Technical Rationale for TPL-007-4 **(28)** Implementation Guidance for TPL-007-4 **(29)** VRF/VSL Justification **(30)** Consideration of Directives TPL-007-4 CAP Extension Request Review Process **(31)** Clean | Redline to Last Posted **(32)**	Final Ballot **(33)** Info Vote	11/13/19 - 11/22/19	Ballot Results **(34)** TPL-007-4	
Draft 1 **TPL-007-4** **(7)** Clean | Redline **(8)** **(9)** Implementation Plan **Supporting Materials** **(10)** Unofficial Comment Form (Word) **(11)** Technical Rationale for TPL-007-4 **(12)** Implementation Guidance for TPL-007-4 **(13)** VRF/VSL Justification **(14)** Consideration of Directives **(15)** Draft ERO Process Update **(16)** Draft Reliability Standard Audit Worksheet (RSAW) Update	Initial Ballot **(20)** Info Vote	8/30/19 - 9/9/19	Ballot Results **(21)** TPL-007-4 **(22)** Non-Binding Poll Results	
	Comment Period **(17)** Info Submit Comments	7/26/19 - 9/9/19	**(18)** Comments Received	**(19)** Consideration of Comments
	Join Ballot Pools	7/26/19 - 8/26/19		
	Send RSAW feedback to: RSAWfeedback@nerc.net			

Drafting Team Nominations **Supporting Materials** (5) Unofficial Nomination Form (Word)	Nomination Period (6) Info Submit Nominations	02/25/19 - 03/26/19		
(1) **Standard Authorization Request** **Supporting Materials** (2) Unofficial Comment Form (Word)	Comment Period (3) Info Submit Comments	02/25/19 - 03/26/19	(4) Comments Received	

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revisions to TPL-007-3 Transmission System Planned Performance for Geomagnetic Disturbance		
Date Submitted:			
SAR Requester			
Name:	Soo Jin Kim		
Organization:	NERC		
Telephone:	404-446-9742	Email:	Soo.jin.kim@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 in order to modify Reliability Standard TPL-007-2.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-2. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54). NERC was directed to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The Standard Drafting Team (SDT) will address FERC's directives in Order No. 851 that require the development and completion of corrective actions plans to mitigate assessed supplemental GMD event vulnerabilities. The SDT will also modify the provisions in Reliability Standard TPL-007-3, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when situations beyond the control of the responsible entity arise. The SDT will also need to evaluate the Canadian variance and make any appropriate changes to the variance based on the modifications arising from FERC Order No. 851.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The potential cost impacts associated with adding corrective action plan requirements for supplemental GMD event vulnerabilities are unknown at this time.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Not Applicable
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator, Transmission Planner, Transmission Owner, Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
Project 2018-01 TPL-007-3 (Canadian Variance). EOP-010-1 Geomagnetic Disturbance Operations
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
Order No. 830 GMD Research Work Plan could help to inform the SDT while making the required modifications to the standard laid out in Order No. 851.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
TPL-007-3 Canadian Variance	The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of the defined benchmark and supplemental GMD events in TPL-007-2 Attachment 1.

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Unofficial Comment Form

Project 2019-01 Modifications to TPL-007-3

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **Project 2019-01 Modifications to TPL-007-3 Standard Authorization Request (SAR)**. Comments must be submitted by **8 p.m. Eastern, Tuesday, March 26, 2019.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

Background Information

The first version of the standard, TPL-007-1, requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with the FERC's directives in Order No. 830. The third version of the standard adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics Background Information. This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the Standrds Drafting Team to consider, if desired.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2019-01 Modifications to TPL-007-3

Informal Comment Period Open through March 26, 2019

Now Available

A 30-day informal comment period for the **Project 2019-01 Modifications to TPL-007-3 Standard Authorization Request (SAR)**, is open through **8 p.m. Eastern, Tuesday, March 26, 2019**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	Project 2019-01 Modifications to TPL-007-3
Comment Period Start Date:	2/25/2019
Comment Period End Date:	3/26/2019
Associated Ballots:	

There were 24 sets of responses, including comments from approximately 67 different people from approximately 51 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the Standards Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1,3,5	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Standards Review Committee 2019-01 Modifications to TPL-007-3	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Terry Bilke	Midcontinent Independent System Operator, Inc.	2	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power	1,6	MRO

						Administration		
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,WECC	ACES Standard Collaborations	John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3,6	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Kagen DelRio	North Carolina Electric Membership Cooperative	3,4,5	SERC
					Ryan Strom	Buckeye	5	RF

						Power, Inc.		
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
Eversource Energy	Quintin Lee	1,3		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
PSEG - Public Service Electric and Gas Co.	Sean Cavote	1,3	FRCC,NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	

Comment

It is our view that the original purpose of the supplemental event is to investigate the impact of local enhancement of the generated electric field from a GMD event on the transmission grid. This requires industry to take a study approach in which the GICs are calculated with the higher, enhanced electric field magnitude of 12 V/km (adjusted for location and ground properties) applied to some smaller defined area while outside of this area the benchmark electric field magnitude of 8 V/km (also adjusted for location and ground properties) is applied. This smaller area is then systematically moved across the system and the calculations are repeated. This is necessary as the phenomenon could occur anywhere on the system. Using this Version 2 methodology, every part of the system is ultimately evaluated with the higher electric field magnitude.

In our view, the supplemental event represents a more extreme scenario. As such, adding a corrective action plan requirement to the supplemental event obviates the need for studying the benchmark event. Rather than pursuing a Corrective Action Plan for the existing Supplemental GMD Vulnerability Assessment, we believe the SDT *should instead pursue only one single GMD Vulnerability Assessment using a reference peak geoelectric field amplitude* not determined soley by non-spatially averaged data. This would be preferable to requiring two GMD Vulnerability Assessments, both having Corrective Action Plans and each having their own unique reference peak geoelectric field amplitude. When the Supplemental GMD Vulnerability Assessment was originally developed and proposed, there was no CAP envisioned for it. Because of this, one could argue the merits of having two unique assessments, as each were different not only in reference peak amplitude, but in obligations as well. What is being suggested in this SAR however, is essentially having two GMD Vulnerability Assessments requiring Corrective Action Plans but with different reference peak geoelectric field amplitudes (one presumably higher than the other). It would be unnecessarily burdensome, as well as illogical, to have essentially the same obligations for both a baseline and supplemental vulnerability assessment. One again, we believe a more prudent path would be for the SDT to determine an agreeable reference peak geoelectric field amplitude for a single GMD Vulnerability Assessment that potentially requires a Corrective Action Plan.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	No
Document Name	

Comment

CHPD does not agree with requiring the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Entities have only just begun the process of evaluating the benchmark GMD event and developing mitigation measures. The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios

such as the supplemental event. CHPD does not agree with replacing the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis. Since R7.4 is for “situations beyond the control of the entity,” it does not matter if the extensions are considered on a case-by-case basis as the entity will not be able to comply with the CAP timeline as the situation was beyond their control. Adding the case-by-case basis would increase the administrative burden to entities while adding very little benefit to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM agrees with simulating and studying the impacts of localized peak geoelectric fields covered under the supplemental GMD event in the GMD Vulnerability Assessment. These efforts help to improve the overall understanding of the impacts to the BES as well as gauge system performance under more severe conditions. However, the supplemental GMD event should be considered as an extreme event and although useful to create situational awareness, it should not mandate design requirements. The situation is analogous to TPL-001-4 extreme (low probability) events where only an evaluation is performed of the possible actions designed to reduce the likelihood or mitigate the consequences of those events. PJM recommends that the Drafting Team not require Corrective Action Plan(s) for the supplemental GMD event.	
Likes 0	
Dislikes 0	
Response	
Matthew Lewis - Lower Colorado River Authority - 1,5	
Answer	No
Document Name	
Comment	
NERC TPL-001-4 sets forth requirements for TPs to establish a Corrective Action Plan when the analysis indicates an inability of the System to meet the performance requirements for planning events shown in Table 1. The analysis of an extreme event in Table 1 that results in Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted, but no Corrective Action Plan is required under an extreme event. Since the supplimental analysis may be considered an extreme event to the benchment assessment, then the CAP would not be required for the supplemental analysis to be consistant with TPL-001-4.	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Given that FERC order No. 851 extends the corrective action plan to the supplemental GMD event vulnerabilities, the scope should include adding a variance similar to D.A. 7.3. for the new requirement to cover the CAP timelines/milestones associated with regulatory approvals in Canada, where applicable.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
The proposed scope of the SAR is appropriate to address FERC order 851. However, we suggest expanding the scope of the SAR to provide the Standard Drafting Team with the ability to consider making a revision to "Table 1: Steady State Planning GMD Event". The recommendation is to add an item "d." to the "Steady State:" criteria: "d. System steady state voltage performance shall be within the criteria established in Requirement R3."	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The NSRF agrees with the proposed scope as described in the Standard. The proposed scope is appropriate to address FERC directives in Order 851. The NSRF would like to suggest that the SDT consider modifying the standard to include only one Corrective Action Plan for Requirement R7 that will mitigate performance issues identified in the benchmark GMD Vulnerability Assessment (R4) and/or the supplemental GMD Vulnerability Assessment (R8). If an entity identifies vulnerabilities for the benchmark and the supplemental assessment, the NSRF believes that the CAP for the more severe	

supplemental assessment will mitigate the vulnerabilities identified in the benchmark assessment.	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 1,3,4	
Answer	Yes
Document Name	
Comment	
City Utilities supports comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA fully supports efforts already in flight to refine the earth resistance modeling and modification to software study tools to produce results that more closely represent real-life GIC conditions. These refinements are expected to obtain computation of locally varying electric field magnitude and direction for use in computing GIC flow in a modeled transmission network, such that, calculated GIC flow more closely represents actual flows during a GMD event. BPA is aware of work being done by vendors of commercially available study software, and geophysics researchers, to refine GIC modeling in alignment with the present level of understanding of the physics involved. The path they are on is clearly heading towards obtaining more refined computation capabilities, within the study tools we use for GIC analysis work, where small area localized conditions are included. BPA's concern is that this capability does not presently exist within the study tools, and as such, study work would be using widely varying assumptions. BPA believes this variability will increase the likelihood of results that are not representative of actual GIC flow and increase the risk of developing corrective actions that are not beneficial or make matters worse. Worse in that, an action may actually put the system in a less stable state after the action when compared to riding through the event without taking an action that is actually unnecessary. BPA believes that this Reliability Standard (TPL-007) should not request study work beyond the capacities of the study tools until those tools are made capable of producing refined studies requested by the FERC order No. 851.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	

To replace the Corrective Action Plan time-extension provision in Requirement R7.4 with a process through, which extensions of time are considered on a case-by-case basis please consider the following:

(1) A clear criteria for approval and disapproval of the extension of time.

(2) An appeal process for revisiting timetables that are not agreed upon by the Responsible Entity and the Regional Entity.

(3) Clearly identifying what supporting documentation is acceptable in the new process.

Another item for consideration is to attach a guideline to the standard that addresses the following questions:

(1) How will the reviews be scheduled and address who are the participants and their role in the new process?

(2) What means will this review be conducted (conference call or in-person)

(3) Does the review team have time parameters they will enforce?

(4) Will there be circumstances that would be able to by-pass the review and provide a standard extention time that if there are circumstances outside of those, then the case review be concluded?

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group (SSRG) supports the proposed scope as described in the SAR.

The SSRG recommends the Standards Drafting Team (SDT) consider the potential of redundancy in the development of two Correction Action Plans (CAPs).

The SSRG reviewed Paragraph 2, from Attachment 1, Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events. The SSRG recommends that the SDT consider that one CAP could cover both studies.

"*The supplemental GMD event is composed of similar elements as described above (Benchmark), except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform2.*

Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - Public Service Electric and Gas Co. - 1,3, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	

The proposed scope of the SAR is appropriate to address FERC order 851. However, we suggest expanding the scope of the SAR to provide the Standard Drafting Team with the ability to consider making a revision to "Table 1: Steady State Planning GMD Event." The recommendation is to add an item "d." to the "Steady State:" criteria: "d. System steady state voltage performance shall be within the criteria established in Requirement R3."

Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee 2019-01 Modifications to TPL-007-3	
Answer	Yes
Document Name	
Comment	

ISO/RTO Standards Review Committee ("SRC") members CAISO, ERCOT, IESO, MISO, NYISO, and SPP agree that the scope of the SAR aligns with

the directives of FERC in Order No. 851.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anton Vu - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the Standrds Drafting Team to consider, if desired.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee 2019-01 Modifications to TPL-007-3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SSRG recommends the SDT consider developing a non-exclusive list of extension examples.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
It is stated in the SAR that “The potential cost impacts associated with adding corrective action plan requirements for supplemental GMD event vulnerabilities are unknown at this time.” Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions. Thank you for the opportunity to comment.	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the standards authorization request process include input from FERC so as to thoroughly scope each standard to ensure it includes all of FERC's desired content prior to it being submitted for FERC approval. This would help eliminate the potential for changes to new standards being ordered simultaneously with the approval of the same standard. Reclamation also recommends FERC provide ample time for NERC to develop standards to avoid the problem of improperly scoped standards being quickly thrown together simply to meet short deadlines.	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 1,3,4	
Answer	
Document Name	
Comment	
City Utilities supports comments from the MRO NSRF.	

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

The NSRF suggest expanding the scope of the SAR to provide the SDT with the ability to consider removing or revising requirement R11 and R12. The requirements to have a process to collect GMD data is not necessary in TPL-007 because that data will not be used in the Planning Analysis. Furthermore, the GMD data is not needed to complete the benchmark or supplemental vulnerability assessments.

As an example, see the MISO TPL-007-2 flowchart below. The monitoring requirements are outside the requirement flowchart for Planning Analysis and vulnerability assessment. If this data is needed for GMD research, I believed these requirements are covered by the Section 1600 data request.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5

Answer	
Document Name	

Comment

Nothing further

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer	
Document Name	

Comment

it would be beneficial to develop a guideline with as much as details as possible for entities to follow.

Likes 0	
Dislikes 0	

Response

Unofficial Nomination Form

Project 2019-01 Modifications to TPL-007-3
Standard Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2019-01 Modifications to TPL-007-3** standard drafting team (SDT) members by **8 p.m. Eastern, Tuesday, March 26, 2019.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Transmission System Planned Performance for Geomagnetic Disturbance Events

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued an Order No. 851 directing NERC to develop and submit modifications to Reliability Standard TPL-007-3 to require the development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. In addition, Order No. 851 directs NERC to modify the provisions in TPL-007-3, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when situations beyond the control of the responsible entity arises. FERC directs NERC to submit the modifications for approval within 12 months from the effective date of Reliability Standard TPL-007-3.

Standard affected: TPL-007-3

A significant time commitment is expected of SDT members to meet the regulatory deadline established in Order No. 851. SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately one face-to-face meeting per quarter can be expected (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the drafting team sets forth. NERC is seeking individuals from the United States and Canada who possess experience in transmission planning and an understanding of GMD studies.

Name:	
Organization:	
Address:	
Telephone:	
Email:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.
☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.
☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ WECC
☐ FRCC	☐ RF	☐ NA – Not Applicable
☐ MRO	☐ SERC	

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2019-01 Modifications to TPL-007-3

Nomination Period Open through March 26, 2019

Now Available

Nominations are being sought for standard drafting team members through **8 p.m. Eastern, Tuesday, March 26, 2019**.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Linda Jenkins. An unofficial Word version of the nomination form is posted on the Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be one face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous drafting team experience is beneficial but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the standard drafting team in April 2019. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of proposed standard for formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July – September 2019
45-day formal comment period with additional ballot	October – December 2019
45-day formal comment period with second additional ballot	January – March 2020
10-day final ballot	April 2020
Board adoption	May 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-4
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.2.** Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.3.** Transmission Owner who owns a Facility or Facilities specified in 4.2; and
     - **4.1.4.** Generator Owner who owns a Facility or Facilities specified in 4.2.
   - **4.2. Facilities:**
     - **4.2.1.** Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. **Effective Date:** See Implementation Plan for TPL-007-4.
6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ERO approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ERO approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R12 and R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

<table>
<tr><th colspan="5">Table 1: Steady State Planning GMD Event</th></tr>
<tr><td colspan="5">Steady State:
a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.</td></tr>
<tr><th>Category</th><th>Initial Condition</th><th>Event</th><th>Interruption of Firm Transmission Service Allowed</th><th>Load Loss Allowed</th></tr>
<tr><td>Benchmark GMD Event – GMD Event with Outages</td><td>1. System as may be postured in response to space weather information[1], and then
2. GMD event[2]</td><td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td><td>Yes[3]</td><td>Yes[3]</td></tr>
<tr><td>Supplemental GMD Event – GMD Event with Outages</td><td>1. System as may be postured in response to space weather information[1], and then
2. GMD event[2]</td><td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td><td>Yes</td><td>Yes</td></tr>
<tr><th colspan="5">Table 1: Steady State Performance Footnotes</th></tr>
<tr><td colspan="5">1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.</td></tr>
</table>

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \, (V/km) \tag{1}$$

$$E_{peak} = 12 \times \alpha \times \beta_s \, (V/km) \tag{2}$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \tag{3}$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

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[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.
[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

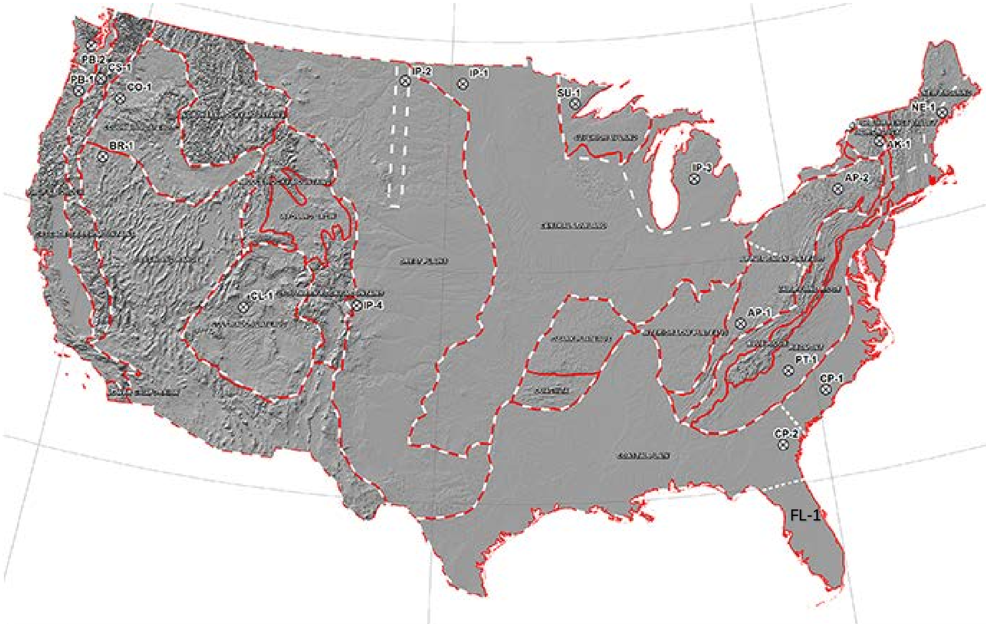

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors

Earth model	Scaling Factor Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

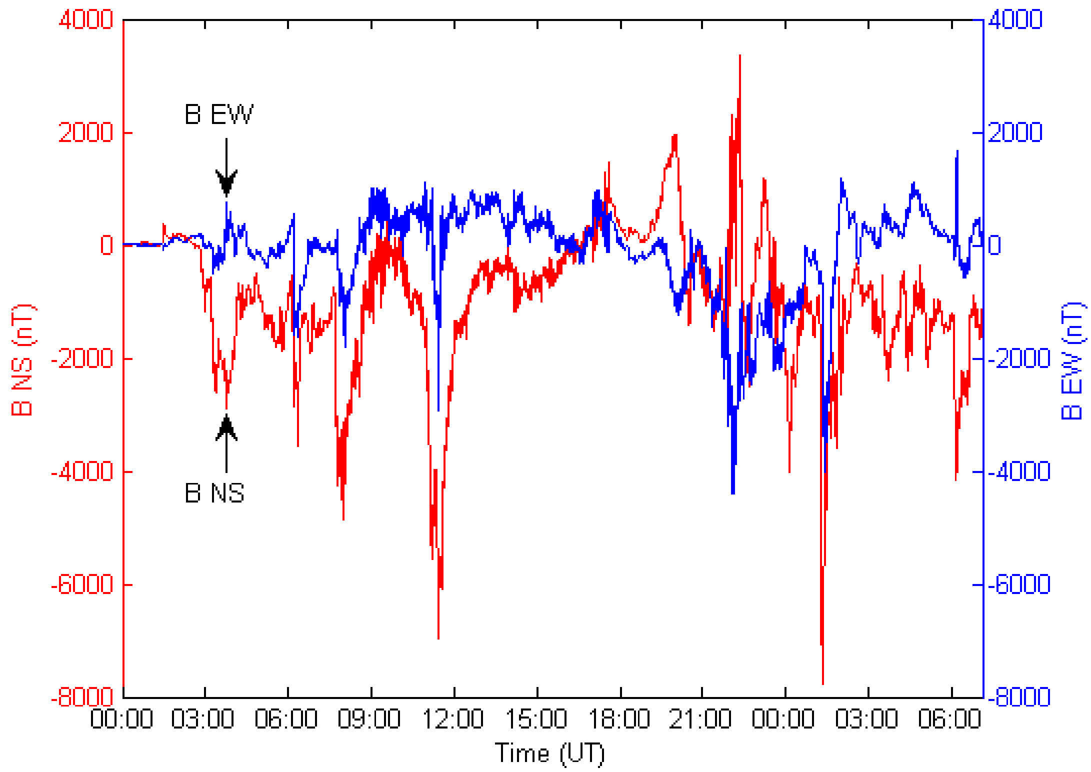

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

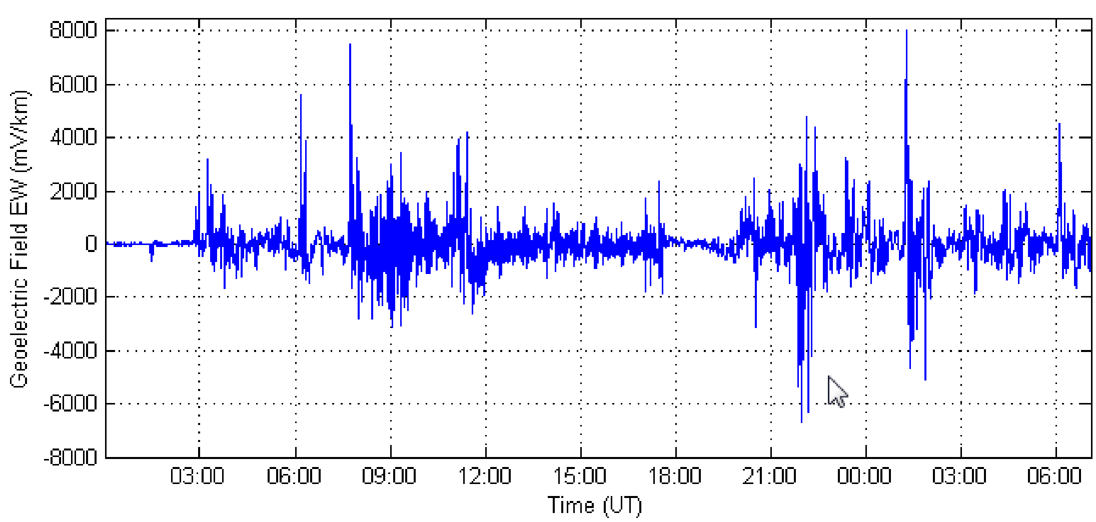

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

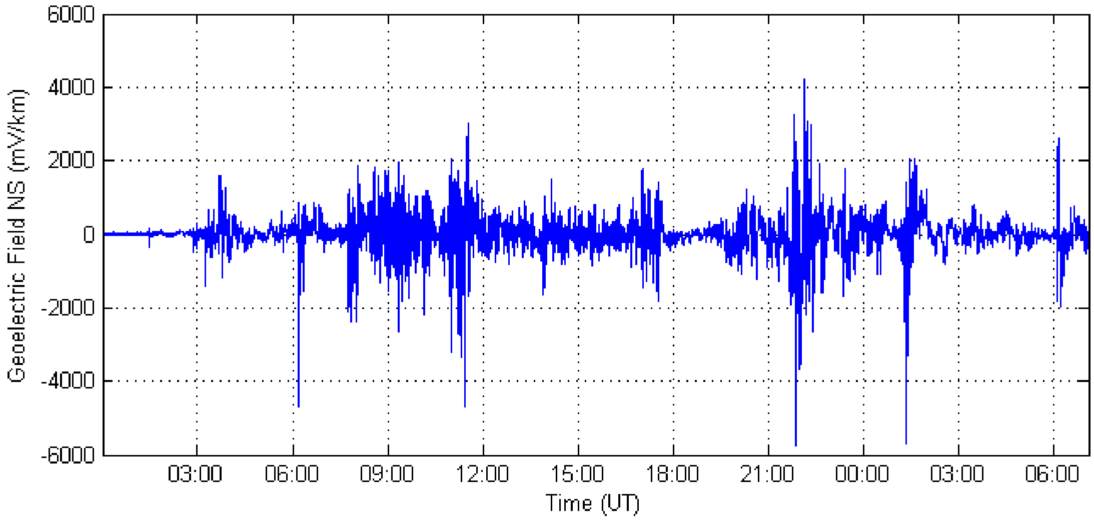

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

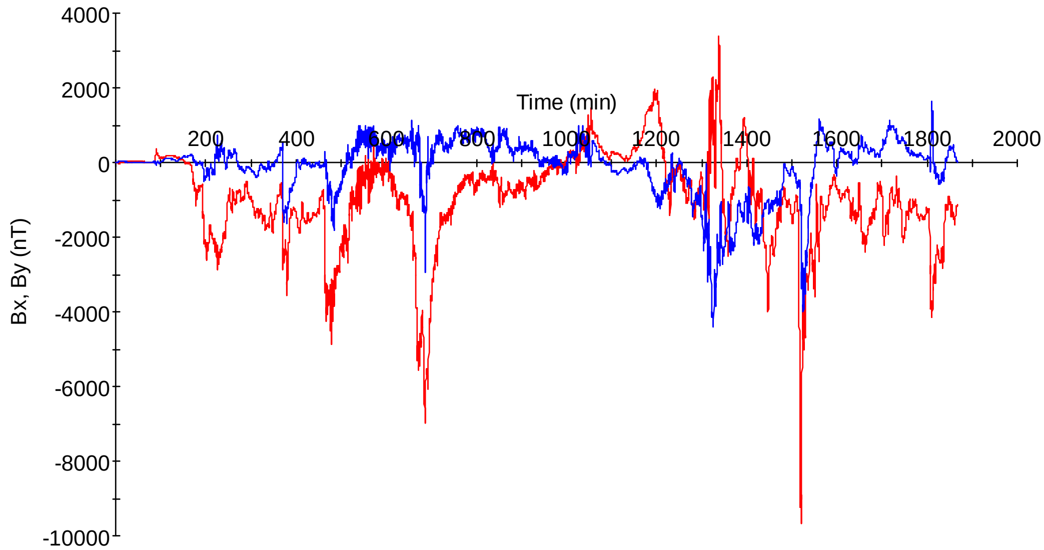

Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

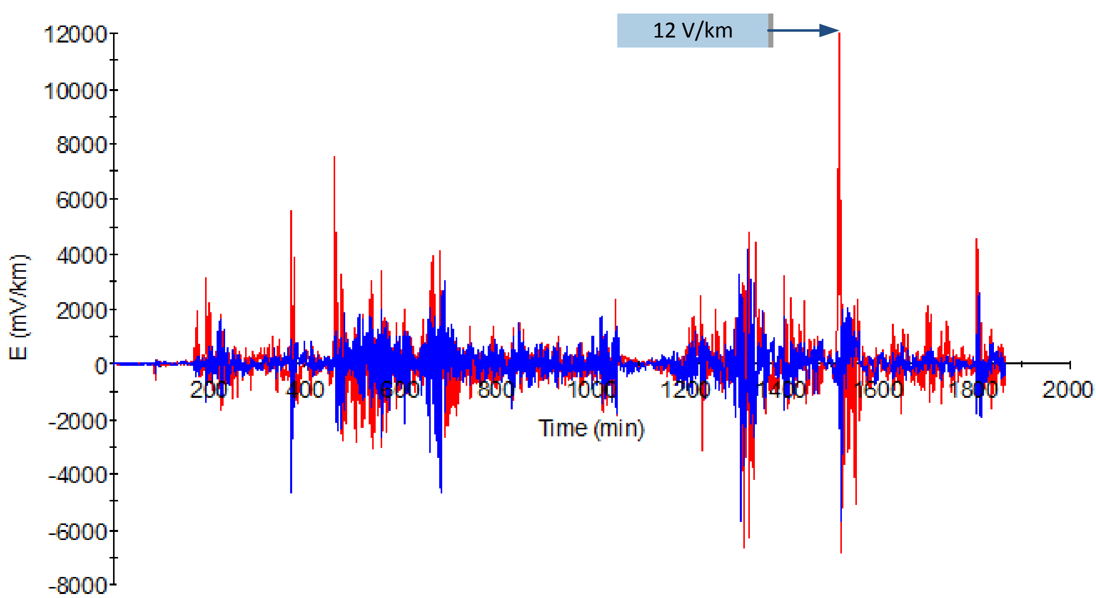

Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The “earth transfer function” is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of proposed standard for formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July – September 2019
45-day formal comment period with additional ballot	October – December 2019
45-day formal comment period with second additional ballot	January – March 2020
10-day final ballot	April 2020
Board adoption	May 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~3~~4

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

    4.1. **Functional Entities:**

    4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

    4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

    4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

    4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

    4.2. **Facilities:**

    4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-~~3~~4.

~~6.~~ **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

~~7.~~6. ~~The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of that in TPL-007-2.~~

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~revision by the responsible entity~~ ERO approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the ERO with a request for extension ~~revised~~ if ~~situations beyond the control of~~ the responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~provided in Part 7.3. The submitted ~~revised~~ CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~:

~~**7.4.1.**~~ Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

~~**7.4.2.**~~**7.4.1.** ~~Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and~~,~~

7.4.3. ~~and the~~ U~~u~~pdated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP ~~results~~, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, ~~-~~that it submitted a request for extension to the ERO if ~~has revised its CAP if situations beyond~~ the responsible entity'~~s~~ is unable to ~~control prevent~~ implement~~ation of~~ the CAP within the timetable provided in Part 7.3~~specified~~. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

~~**8.3.** If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.~~

~~**8.4.**~~**8.3.** The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

~~**8.4.1.**~~**8.3.1.** If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ERO approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

~~R11.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator~~'~~'s planning area or other part of the system included in the Planning Coordinator~~'~~'s GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M10.~~M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12~~1~~.

~~R12.~~R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M11.~~M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13~~2~~.

~~B.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R12~~1~~ and R13~~2~~, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity~~'~~'s completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity~~'~~'s completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity~~'~~'s completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity~~'~~'s Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~'s Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~'s Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~'s Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop ~~have~~ a Corrective Action Plan as required by Requirement R7.
R8.	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;~~ ~~OR~~ The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~'s completed supplemental GMD Vulnerability Assessment failed to satisfy ~~two~~ one of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~'s completed supplemental GMD Vulnerability Assessment failed to satisfy ~~three~~ two of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~'s completed supplemental GMD Vulnerability Assessment failed to satisfy three~~four~~ of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11. ~~The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model. ~~The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.~~
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

~~C.~~D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces ~~A~~all references to "Attachment 1" in the standard ~~are replaced~~ with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP ~~-~~ or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3.–Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

~~D.~~E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \,(V/km) \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_s \,(V/km) \quad (2)$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \quad (3)$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

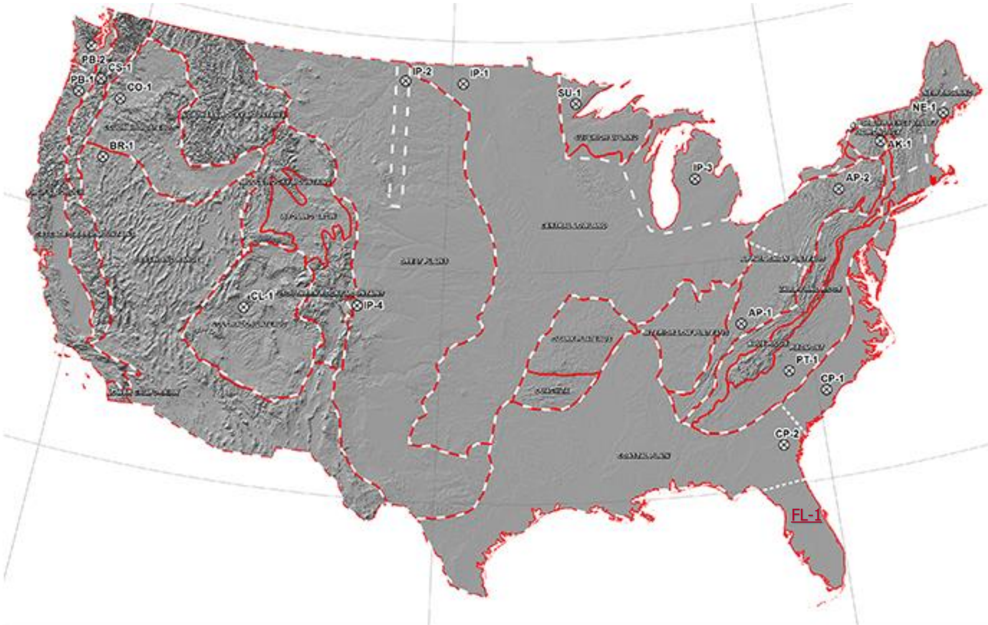

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

~~**Rationale:** Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.~~

~~The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated based on the earth model published on the USGS public website.~~

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

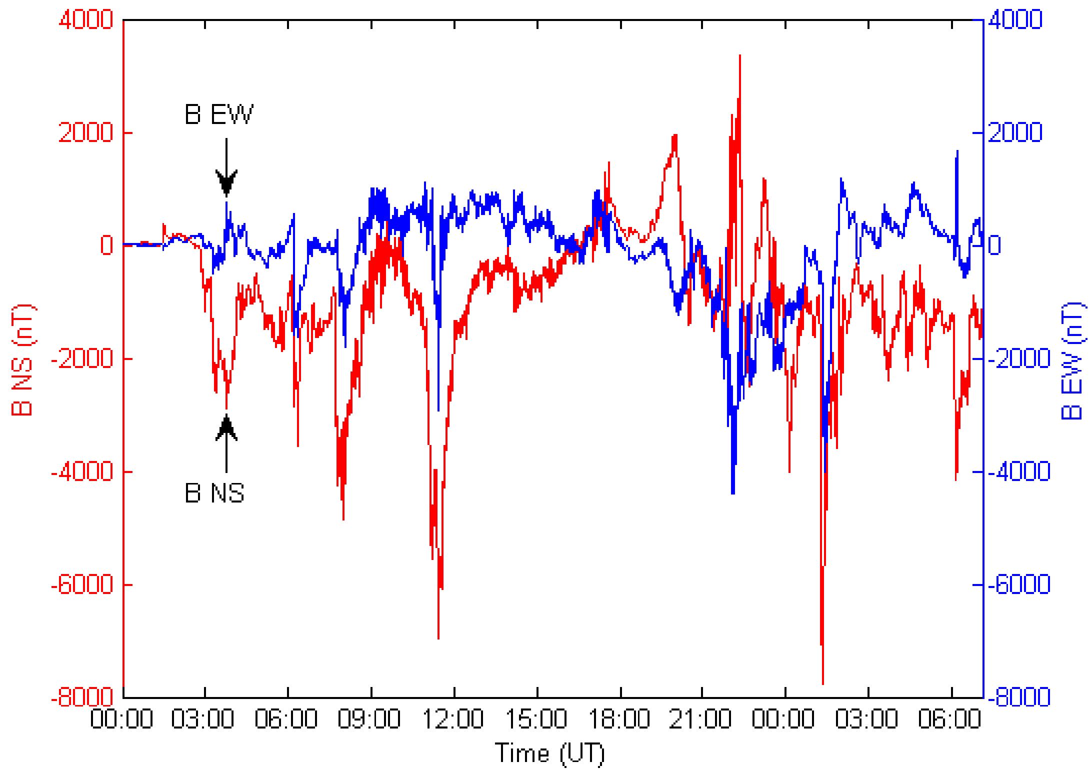

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

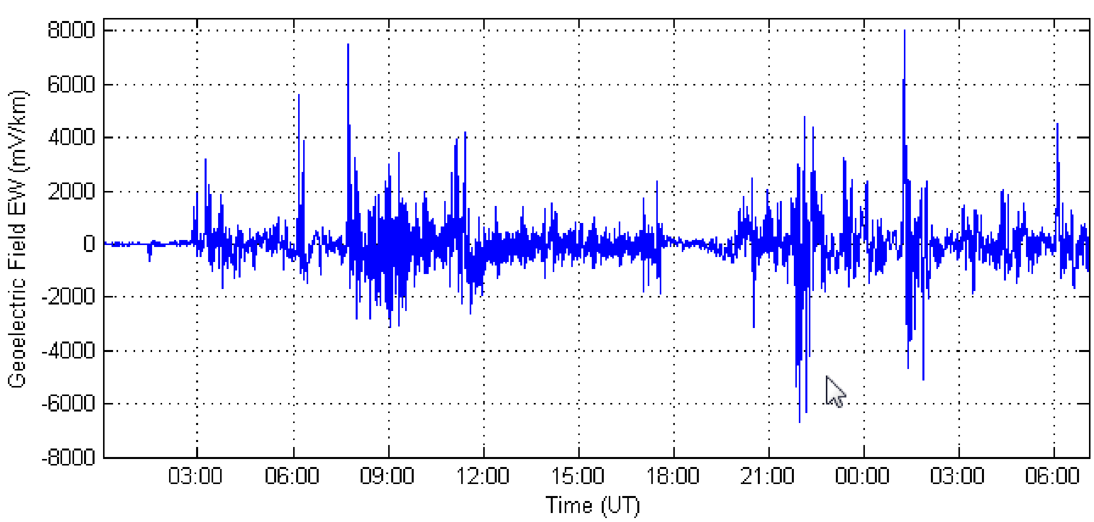

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

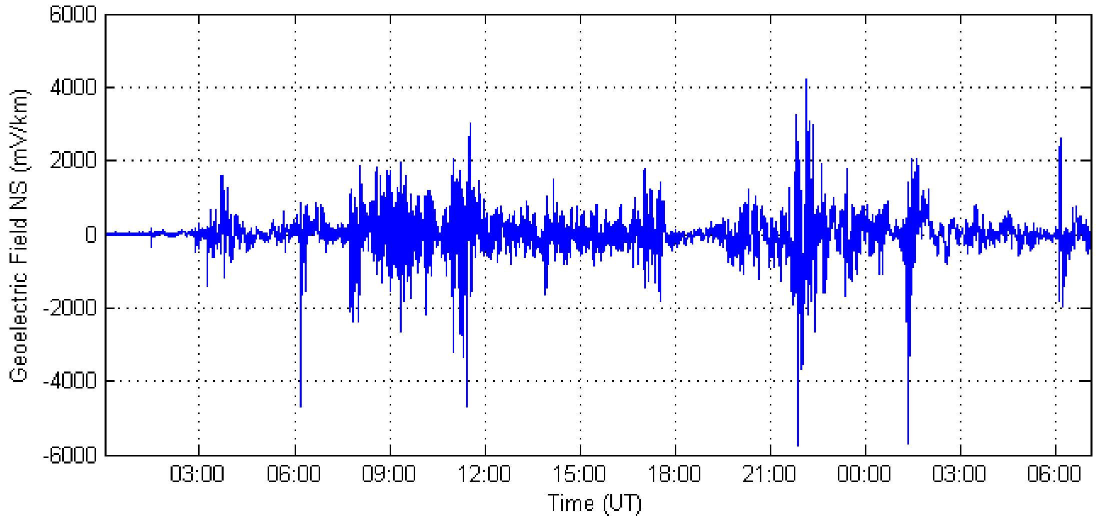

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

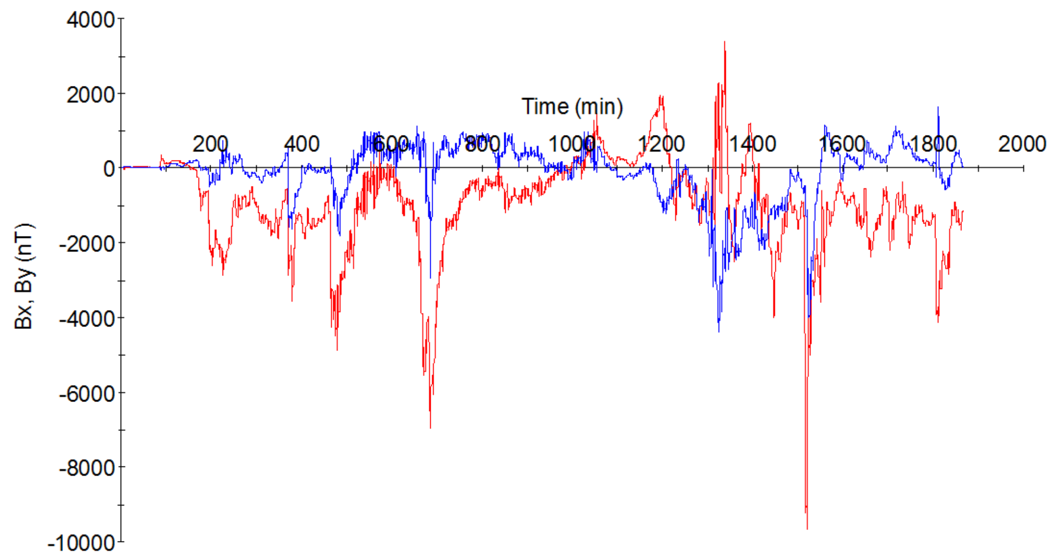

Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

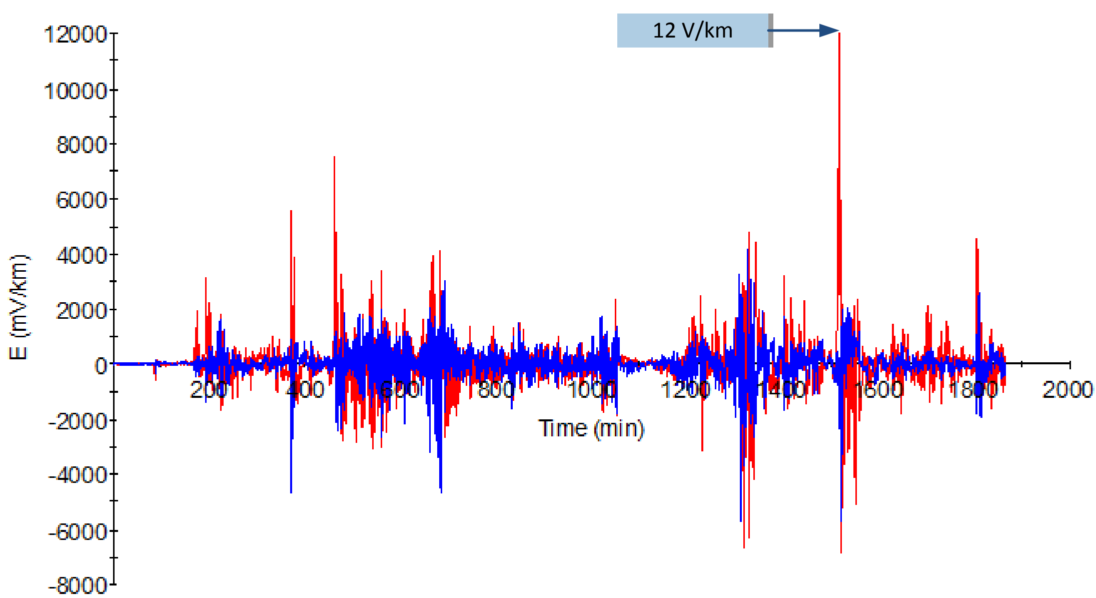

Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1]~~[1]~~ Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

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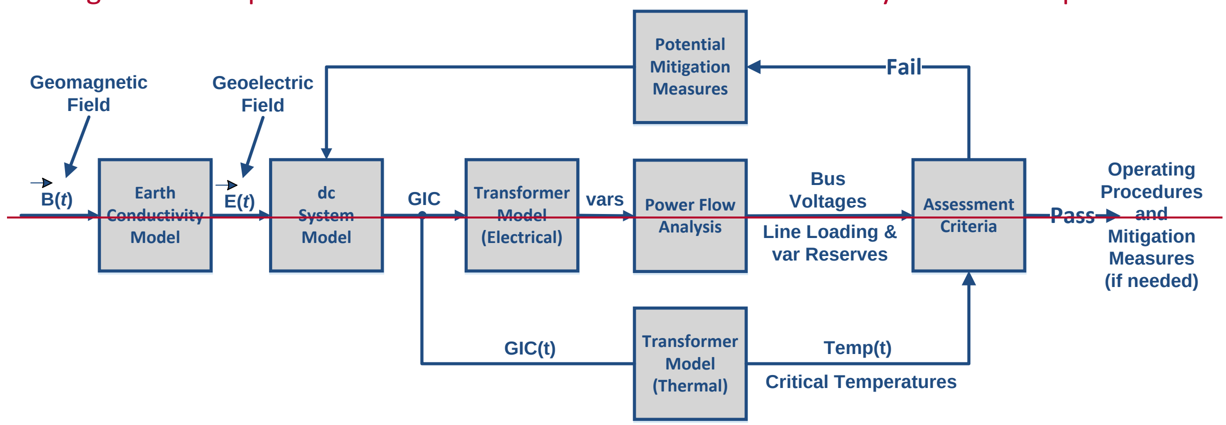
[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

~~[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.~~

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

~~Guidelines and Technical Basis~~

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



~~The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.~~

~~Benchmark GMD Event (Attachment 1)~~

~~The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016[11] white paper includes the event description, analysis, and example calculations.~~

~~Supplemental GMD Event (Attachment 1)~~

~~The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017[12] white paper includes the event description and analysis.~~

~~Requirement R2~~

~~A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide:~~

~~[11] http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.~~
~~[12] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~*Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*, December 2013.[13]~~

~~Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.~~

~~Requirement R4~~

~~The *Geomagnetic Disturbance Planning Guide*,[14] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~Requirement R5~~

~~The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.~~

~~GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time-series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact~~

~~[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.~~

~~[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~assessment. Additional information is in the following section and the *Transformer Thermal Impact Assessment White Paper*,[15] October 2017.~~

~~The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R6~~

~~The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[16] for this requirement. This ERO-Endorsed document is posted on the NERC Compliance Guidance[17] webpage.~~

~~Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[18] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.~~

~~The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R7~~

~~Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*,[19] December 2013. Additional information is available in the *2012 Special Reliability Assessment*~~

~~[15] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~[16] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~

~~[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx.~~

~~[18] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~[19] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~*Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System,*[20] February 2012.~~

~~Requirement R8~~

~~The *Geomagnetic Disturbance Planning Guide,*[21] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.~~

~~Requirement R9~~

~~The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.~~

~~GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.~~

~~The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R10~~

~~The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[22] discussed in the Requirement R6 section above. A later~~

~~[20] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~

~~[21] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~[22] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~

~~version of the *Transformer Thermal Impact Assessment White Paper*,[23] October 2017, has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment.~~

~~Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[24] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.~~

~~The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R11~~

~~Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[25] February 2012. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful for model validation and situational awareness.~~

~~Responsible entities consider the following in developing a process for obtaining GIC monitor data:~~

~~**Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.~~

~~**Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider~~

[23] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
[24] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
[25] ~~http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~

~~monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.~~

~~**Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.~~

~~**Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.~~

~~**Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time~~

~~fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.~~

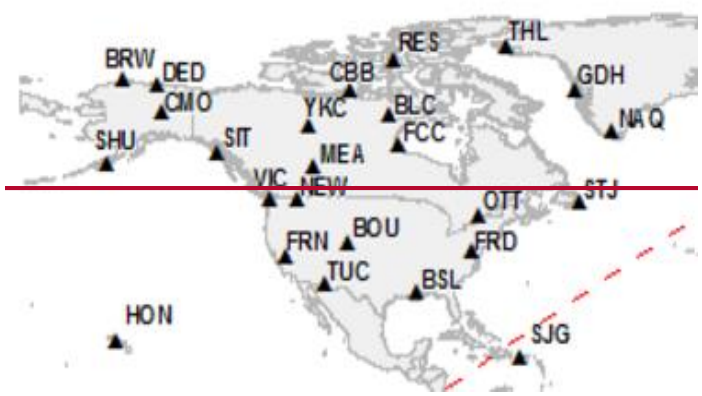
~~**Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.~~

~~**Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).~~

~~Requirement R12~~

~~Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:~~

~~Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:~~[26]



[26] ~~http://www.intermagnet.org/index-eng.php.~~

Implementation Plan

Project 2019-01 Modifications to TPL-007-3

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. No continent-wide requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

General Considerations

This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard TPL-007-4

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1, R2, R5, and R9

Entities shall be required to comply with Requirements R1, R2, R5, and R9 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R12 and R13

Entities shall not be required to comply with Requirements R12 and R13 until the later of: (i) July 1, 2021; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the later of: (i) January 1, 2022; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R3, R4, and R8

Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7

Entities shall not be required to comply with Requirement R7 until the later of: (i) January 1, 2024; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R11

Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.

Retirement Date

Standard TPL-007-3

Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

Unofficial Comment Form

Project 2019-01 Modifications to TPL-007-3

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events**. Comments must be submitted by **8 p.m. Eastern, Monday, September 9, 2019.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

Background Information

The first version of the standard, TPL-007-1, requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with the FERC's directives in Order No. 830. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Questions

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

☐ Yes
☐ No

Comments:

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

☐ Yes
☐ No

Comments:

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

☐ Yes
☐ No

Comments:

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?

☐ Yes
☐ No

Comments:

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

☐ Yes
☐ No

Comments:

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

8. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

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July 2019 - DRAFT Technical Rationale
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Technical Rationale and Justification for Reliability Standard TPL-007-4

July 2019

RELIABILITY | ACCOUNTABILITY

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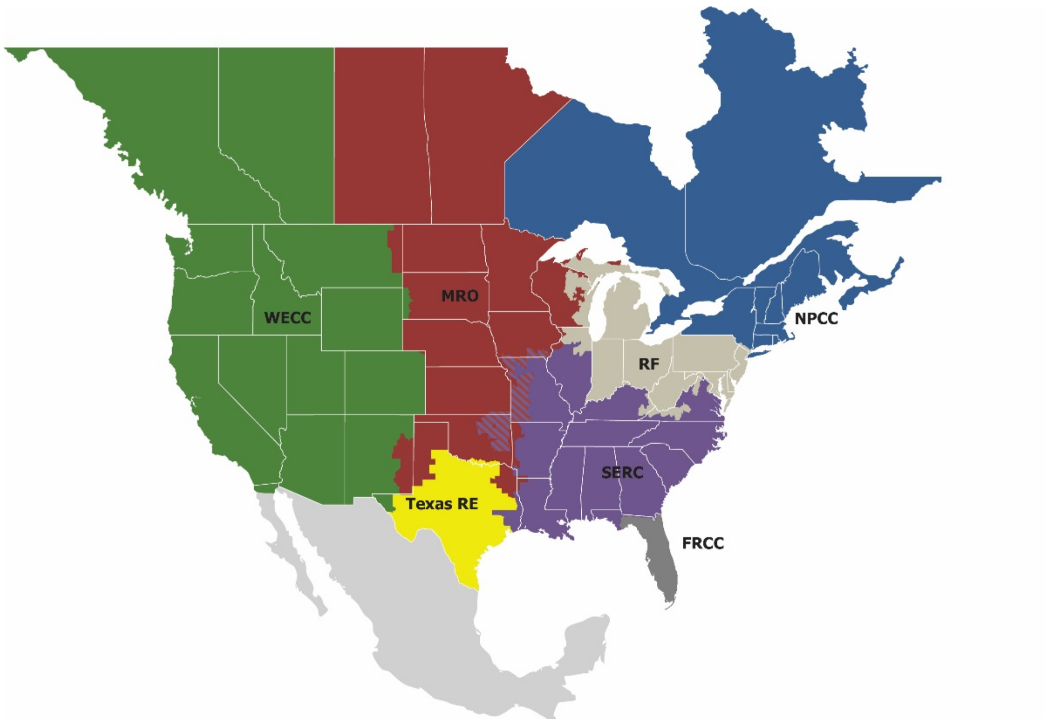
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. It also contains information on the standard drafting team's intent in drafting the requirements. This document, the Technical Rationale and Justification for TPL-007-4, is not a Reliability Standard and should not be considered mandatory and enforceable.

The first version of the standard, TPL-007-1, approved by FERC in Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect Canadian-specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version of the standard, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 with a process through which extensions of time are considered on a case-by-case basis (P 54).

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process. Figure 1 provides an overall view of the GMD Vulnerability Assessment process:

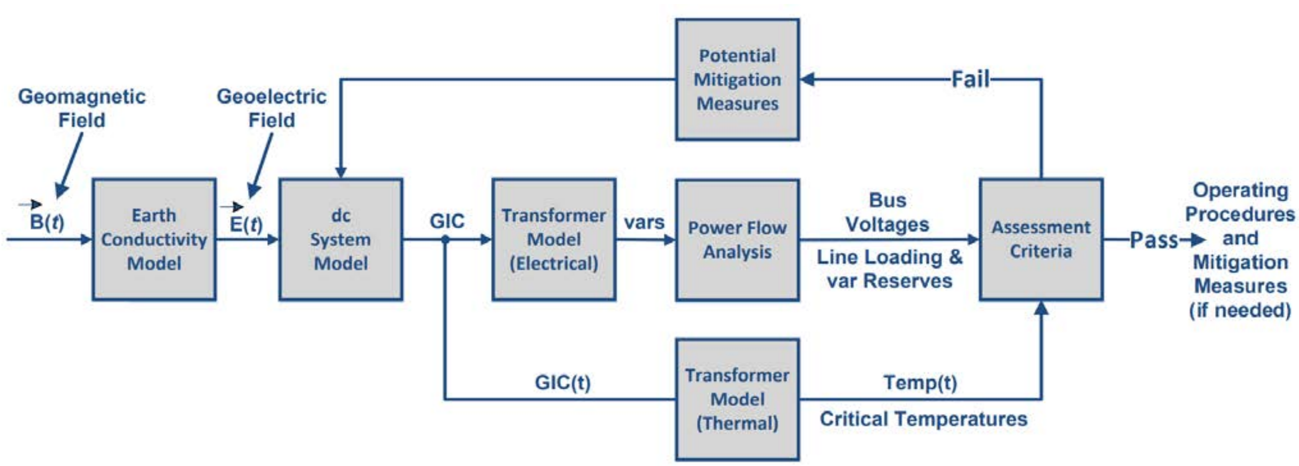


Figure 1. GMD Vulnerability Assessment Process.

Chapter 1 – General Considerations

Rationale for Applicability

Reliability Standard TPL-007-4 is applicable to Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these types of transformers are not included in the applicability for this standard. Terminal voltage describes line-to-line voltage.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016 [4], includes the event description, analysis, and example calculations.

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017 [5], includes the event description and analysis.

Chapter 2 – Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

Chapter 3 – Requirement R4

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Chapter 4 – Requirement R5

The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information for the benchmark thermal impact assessment should be provided in accordance with Requirement R5 each time the benchmark GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 75 Amps per phase, in the benchmark GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the benchmark thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the benchmark GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 5.2 can be used to convert the steady state GIC flows to time-series GIC data for the benchmark transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Chapter 5 – Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

Chapter 6 – Requirement R7

The requirement addresses directives in FERC Order No. 851 to replace the time-extension provision in Requirement R7.4 of TPL-007-2 (and TPL-007-3) with a process through which extensions of time are considered on a case-by-case basis.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 7 – Supplemental GMD Vulnerability Assessment

The requirements address directives in FERC Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (PP 44, 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Chapter 8 – Requirement R8

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Chapter 9 – Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information for the supplemental thermal impact assessment should be provided in accordance with Requirement R9 each time the supplemental GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 85 Amps per phase, in the supplemental GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the supplemental thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the supplemental GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 9.2 can be used to convert the steady state GIC flows to time-series GIC data for the supplemental transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Chapter 10 – Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R9.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

Chapter 11 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for the assessed supplemental GMD event vulnerabilities.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the Geomagnetic Disturbance Planning Guide, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 12 – Requirement R12

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect GIC monitoring data as necessary to enable model validation and situational awareness (PP 88, 90-92).

Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10]. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer and measure dc current flowing through the neutral. Data from GIC monitors is useful for model validation and situational awareness.

The objective of Requirement R12 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 13 – Requirement R13

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect magnetometer data as necessary to enable model validation and situational awareness (PP 88, 90-92).

The objective of Requirement R13 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator’s planning area is obtained from one or more of the above data sources located in the Planning Coordinator’s planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator’s planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator’s planning area.

References

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10. 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System, NERC, Atlanta, GA, February, 2012, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

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Implementation Guidance for Reliability Standard TPL-007-4

July 2019

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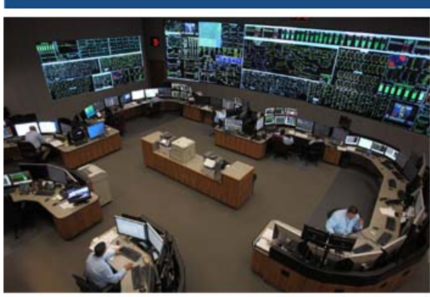


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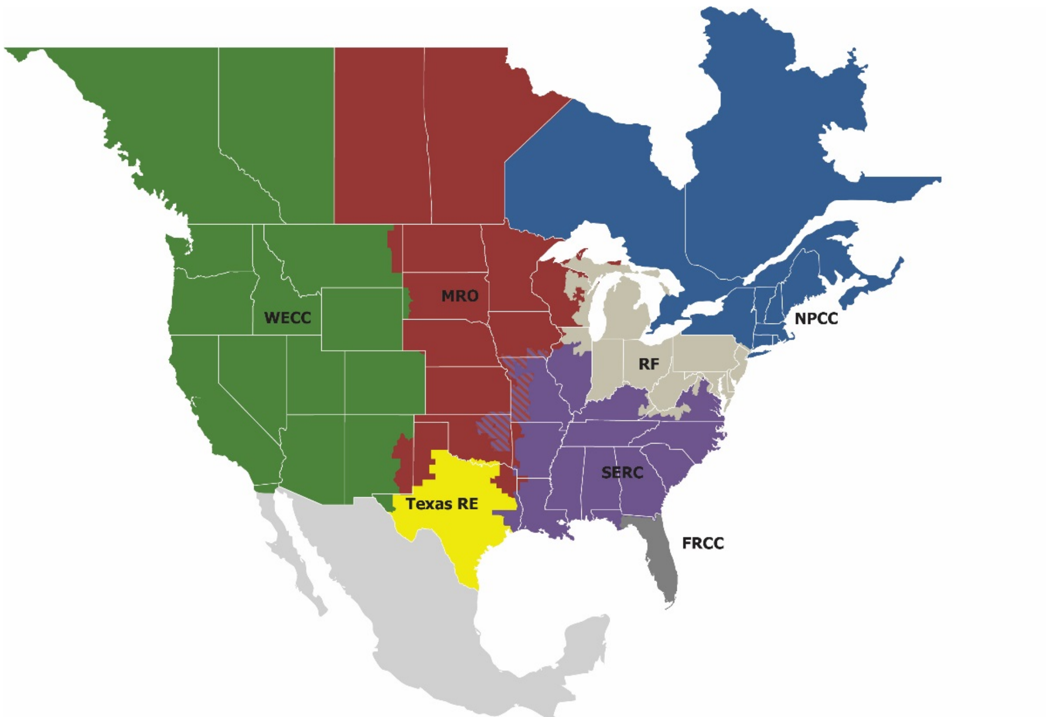

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Introduction

Background

The Standards Project 2019-01 Modifications to TPL-007-3 standard drafting team prepared this Implementation Guidance to provide example approaches for compliance with the modifications to TPL-007 - Transmission System Planned Performance for Geomagnetic Disturbance Events. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches based on engineering judgement, individual equipment and system conditions.

The first version of the standard, TPL-007-1 which was approved in FERC's Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Chapter 1 – Requirement R1

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Chapter 2 – Requirement R2

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These system adjustments could for example include recalling or postponing maintenance outages.

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations, such as this, in the GIC system model, if applicable.

Chapter 3 – Requirement R3

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1: Steady State Planning GMD Event found in TPL-007-4. Steady state voltage limits are an example of System steady state performance criteria.

Chapter 4 – Requirement R4

Distribution of benchmark GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 5 – Requirement R5

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 6 – Requirement R6

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and *the Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5], for additional information.

Approaches for conducting the thermal impact assessment of transformers for the benchmark event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the benchmark event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4) and the Corrective Action Plan (CAP; R7) as necessary.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 7 – Requirement R7

The proposed requirement addresses directives in FERC Order No. 830 for establishing CAP deadlines associated with GMD Vulnerability Assessments. In FERC Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed NERC to establish implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 7.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 8 – Supplemental GMD Vulnerability Assessment

The exact spatial extent, local time of occurrence, latitude boundary, number of occurrences during a GMD event, and geoelectric field characteristics (amplitude and orientation) inside/outside the local enhancement cannot yet be scientifically determined.

TPL-007-4 provides flexibility for Transmission Planners to determine how to apply the supplemental GMD event to the planning area. This guide provides acceptable approaches and boundaries to apply the supplemental event.

1. Spatial extent:
   a. The local geoelectric field enhancement should not be smaller than 100 km (West-East) by 100 km (North-South).
   b. The transmission planner may perform a sensitivity analysis varying the spatial extent. Note that the 100 km North-South spatial extent is better understood than the West-East length, which could be 500 km or more.
   c. The peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) can be applied over the entire planning area. Note that this implies studying a GMD event rarer than 1-in-100 years.
2. Geoelectric field inside the local enhancement:
   a. Amplitude: 12 V/km (scaled to the planning area).
   b. Orientation: at a minimum, a West-East[1] orientation should be considered when applying the supplemental event.
   c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
3. Geoelectric field outside[2] the local enhancement:
   a. Amplitude: should not be smaller than 1.2 V/km (scaled to the planning area); i.e., an order of magnitude smaller than the field inside the local enhancement.
   b. Orientation: at a minimum, a West-East[3] orientation should be considered when applying the supplemental event.
   c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
4. Position of the local enhancement:
   a. The transmission planner may use engineering judgement to position the local enhancement on critical areas of their system. For example, the benchmark vulnerability assessment may identify areas with depressed voltages, lack of dynamic reactive reserves, large GIC flows through transformers, etc. The transmission planner may also consider the impact to critical infrastructure or other externalities.
   b. The transmission planner may systematically move the position of the local enhancement throughout the entire planning area.

[1] West-East geomagnetic reference.

[2] The characteristics of the geoelectric field outside the local enhancement, for example amplitude, orientation, spatial extent, are still being reviewed by the scientific community.

[3] West-East geomagnetic reference.

c. Despite the fact that local enhancements appear to be limited to auroral regions, geomagnetic latitude should not be used as a criterion to position the local enhancement.

The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event. The local enhancement should not be smaller than 100 km by 100 km, the geoelectric field inside the local enhancement is 12 V/km (scaled to the planning area) with West-East orientation, and the geoelectric field outside the local enhancement could be as low as 1.2 V/km (scaled to the planning area) with a West-East orientation.

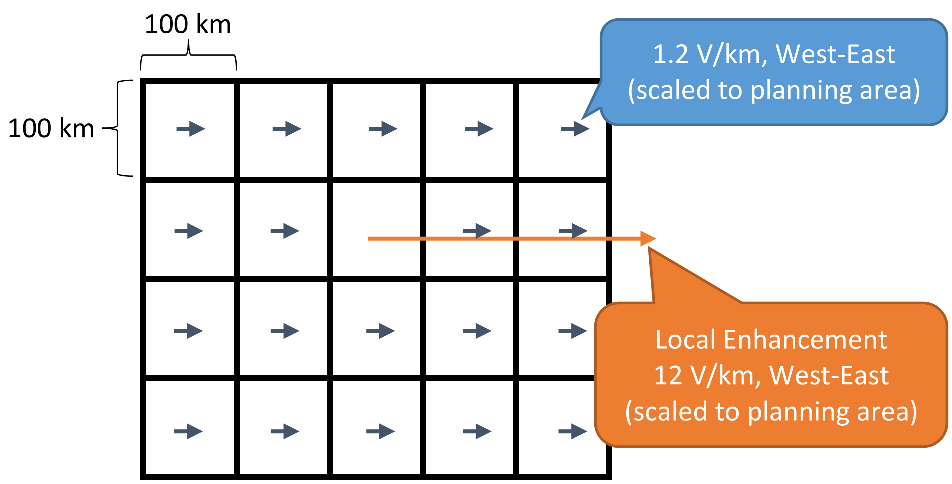


Figure 1. Schematic showing the boundaries to apply the supplemental event.

Chapter 9 – Requirement R8

Distribution of supplemental GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R8, Part 8.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 10 – Requirement R9

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R9, Part 9.1.

The provision of information in Requirement R9 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 11 – Requirement R10

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5] for additional information.

Approaches for conducting the thermal impact assessment of transformers for the supplemental event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the supplemental event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R8) and the Corrective Action Plan (R11) as necessary.

The provision of information in Requirement R10, Part 10.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 12 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for assessed supplemental GMD event vulnerabilities. This requirement is analogous to Requirement R7, such that CAPs are developed within one year from the completion of supplemental GMD Vulnerability Assessments and establishment of implementation deadlines after the completion of the CAP as follows:

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 11.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 11.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 13 – Requirement R12

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- Monitor locations. An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (for example subways or light rail) may be unreliable.

- Monitor specifications. Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (for example -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- Sampling Interval. An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- Collection Periods. The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- Data format. Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

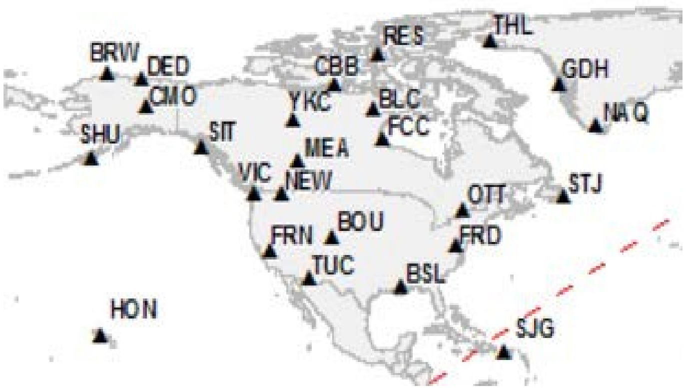
- Data retention. The entity's process should specify data retention periods, for example one (1) year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- Additional information. The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (for example three-phase or single-phase).

Chapter 14 – Requirement R13

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey (USGS) and Natural Resources Canada (NRCan), see figure below for locations [7];



- Research institutions and academic universities; and
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012 [8].

References

1. FERC Order No. 779, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order779_GMD_RM12-22_20130516.pdf
2. FERC Order No. 830, https://www.nerc.com/filingsorders/us/FERCOrdersRules/E-4.pdf
3. FERC Order No. 851, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-3_Order%20No%20851.pdf
4. Transformer Thermal Impact Assessment White Paper, ERO Enterprise-Endorsed Implementation Guidance, NERC, Atlanta, GA, October 28, 2016, https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf
5. Screening Criterion for Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Screening_Criterion_Clean_2017_October_Clean.pdf
6. Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Thermal_Impact_Assessment_2017_October_Clean.pdf
7. International Real-Time Magnetic Observatory Network, http://www.intermagnet.org/index-eng.php
8. INTERMAGNET Technical Reference Manual, Version 4.6, 2012, http://www.intermagnet.org/publications/intermag_4-6.pdf

Violation Risk Factor and Violation Severity Level Justification

Project 2019-01 Modifications to TPL-007-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification for TPL-007-4, Requirement R1
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R1
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R2
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R2
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R3
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R3
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R4
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R4
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R5
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R5
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R6
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R6

The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R7

The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R7

The VSL did not substantively change from the previously FERC-approved TPL-007-3 Reliability Standard. In the Severe VSL, the word "have" was replaced with "develop" to more closely reflect the language of the Requirement.

VRF Justification for TPL-007-4, Requirement R8

The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R8

The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R9

The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R9

The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R10

The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R10

The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R11

The justification is provided on the following pages.

VSL Justification for TPL-007-4, Requirement R11

The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSLs for TPL-007-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications for TPL-007-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs retain the VSLs from FERC-approved TPL-007-3 with the exception of removing one part of the lower VSL to reflect the removal of subpart 8.3 in TPL-007-3. As a result, the proposed VSLs do not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VSLs for TPL-007-4, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance. Further, the VSLs are consistent with those assigned for Requirement R7, pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is being proposed for this requirement.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The proposed VRF is consistent among other FERC approved VRFs within the standard, specifically Requirement R7 pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a supplemental GMD Vulnerability Assessment could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Consideration of Issues and Directives

Project 2019-01 Modifications to TPL-007-3

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Modify the provision in Reliability Standard TPL-007-2, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]", by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis. Under this option, responsible entities seeking an extension would submit the information required by Requirement R7.4 to NERC and the Regional Entities for their consideration of the request.	FERC Order No. 851, P 5 and P 50	The SDT proposed the modified language in Requirement R7.3 and R7.4 to require time extensions for completing CAPs be submitted to the ERO for approval. The proposed modified language reads as follows: 7.3. Include a timetable, subject ~~to revision by the responsible entity~~ ERO approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall: 7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and 7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP. 7.4. Be submitted to the ERO with a request for extension ~~revised~~ if ~~situations beyond the control of~~ the responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~ provided in Part 7.3. The submitted ~~revised~~ CAP

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		shall document the following~~, and be updated at least once every 12 calendar months until implemented~~: 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of each responsible entity; ~~7.4.2 Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~ 7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable;~~,~~ and 7.4.3 ~~the u~~Updated timetable for implementing the selected actions in Part 7.1.
Submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.	FERC Order No. 851, P 4 and P 39	The SDT drafted TPL-007-4 Requirement R11 to address require CAPs for supplemental GMD vulnerabilities and to require extensions to these plans to be approved by NERC and the Regional Entities, as appropriate, in situations beyond the control of the responsible entity. This language is the same as the modified Requirement R7 which addresses CAPs for the benchmark GMD vulnerability assessment. Requirement R8 was also modified to remove the original R8.3 which stated "an evaluation of possible actions designed

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted”

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DRAFT TPL-007-4 CAP Extension Request Review Process

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Introduction

Background

This Electric Reliability Organization (ERO) Enterprise[1] TPL-007-4 Corrective Action Plan (CAP) Extension Review Process document addresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs) developed under TPL-007-4 to ensure a timely, structured and consistent approach to CAP extension request submittals and processing.

NERC Compliance Assurance will maintain this document under existing ERO Enterprise processes. This document will be reviewed and updated by NERC Compliance Assurance, as needed.

[1] The ERO Enterprise is comprised of NERC and the Regional Entities.

Process Overview

If a registered entity (entity) has determined that a Corrective Action Plan (CAP) developed in accordance with TPL-007-4 R7 or R11 cannot be met in the timetable provided per Part 7.3 or 11.3 due to situations beyond the control of the responsible entity, then the entity will submit a extension request to the ERO Enterprise for approval prior to the original required CAP completion date.

The steps outlined here should be followed to ensure a timely, structured and consistent approach to extension request submittals and processing.

Step 1 – Registered Entity Submittal

If a registered entity (entity) determines that it cannot meet the required timetable for completing a CAP, the entity will contact their Compliance Enforcement Authority (CEA) to coordinate submittal of an extension request. The entity should submit the request to their CEA using the template provided in **Appendix A: Entity Submittal Template** or through an alternate method designated by the CEA that includes the same information.

Entities are encouraged to submit the extension request as soon as they are aware they will not meet the CAP completion date to allow the ERO Enterprise time to approve the extension request before the original required completion date.

All CAP extension requests must be approved by the ERO Enterprise prior to original required CAP completion date.

Step 2 – ERO Enterprise Review

The CEA will ensure that all information detailed in TPL-007-4 Part 7.4 or 11.4 and requested in the Entity Submittal Template is provided in the entity's extension request submittal. The CEA will work with the entity to provide any missing information.

The CEA will notify NERC of the extension request submittal. The CEA and NERC will then perform a joint review of (1) the situation(s) beyond the control of the entity preventing implementation of the CAP within the identified timetable; and (2) the revisions to the CAP and updated timetable for implementing the selected actions. Any additional information requested by the ERO Enterprise to support the extension request review will be coordinated by the CEA.

The Standard language states that an entity will submit an extension request for a full or partial delay in the implementation of the CAP within the timetable provided in TPL-007-4 Part 7.3 or 11.3. The CEA and NERC will determine whether to approve the extension request based on the specific facts and circumstances provided as to how the situations causing the delay in completing the CAP are beyond the control of the entity.

Step 3 – Registered Entity Notification

The CEA will communicate the ERO Enterprise approval or denial of the extension request to the entity along with the rationale for the determination.

Appendix A: Entity Submittal Template

[Will be formatted into a form for submission that includes the following information]

Entity name:

NCR#:

Primary entity contact name and information:

Coordinated Oversight Group # (if applicable):

Regional Entities impacted (for MRREs only):

Start date of CAP:

Original completion date of CAP:

Description of system deficiencies identified and selected actions to achieve required System performance per TPL-007-4 Part 7.1:

Circumstances causing the delay for fully or partially implementing the selected actions:

Description of revisions to the selected actions, if applicable:

New proposed completion date of CAP:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1					X[3]						X[4]	
R2					X[3]						X[4]	
R3					X[3]						X[4]	
R4					X[3]						X[4]	
R5					X[3]						X[4]	
R6			X[5]						X[6]			
R7					X[3]						X[4]	
R8					X[3]						X[4]	

1 NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

2 Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
3 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2.
4 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2.
5 Generator Owner who owns a Facility or Facilities specified in 4.2.
6 Transmission Owner who owns a Facility or Facilities specified in 4.2.

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R9					X[3]						X[4]	
R10			X[5]						X[6]			
R11					X[3]						X[4]	
R12					X[3]						X[4]	
R13					X[3]						X[4]	

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			
R9			
R10			
R11			
R12			
R13			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R1

This section to be completed by the Compliance Enforcement Authority

	Confirm existence of documentation identifying the individual and joint responsibilities for the responsible entities, defined in Requirement R1, for maintaining models, performing studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate maintenance of System models and GIC System models for the responsible entity's planning area.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R2
This section to be completed by the Compliance Enforcement Authority

	Verify the responsible entity maintained System models and GIC System models for performing studies for benchmark and supplemental GMD Vulnerability Assessments.

Note to Auditor:
Benchmark and supplemental GMD Vulnerability Assessments require a GIC System model, which is a direct current representation of the System, to calculate GIC flow. In benchmark and supplemental GMD Vulnerability Assessments, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. See the *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System* for details on developing the GIC System model.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1.

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Criteria for acceptable System steady state voltage performance for the entity's System during the GMD events described in Attachment 1.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R3
This section to be completed by the Compliance Enforcement Authority

	Verify the responsible entity has criteria for acceptable System steady state voltage performance for its System during the GMD events described in TPL-007 Attachment 1.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis.

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied

evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated copies of the current and preceding benchmark GMD Vulnerability Assessments of Near-Term Transmission Planning Horizon.
Evidence the study or studies include System On-Peak Load and System Off-Peak Load conditions for at least one year within the Near-Term Transmission Planning Horizon.
Evidence the study or studies were conducted based on the benchmark GMD event described in Attachment 1 for the steady state planning benchmark GMD event to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.
Dated evidence that the responsible entity provided the benchmark GMD Vulnerability Assessment within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners.
Dated evidence that the responsible entity provided the benchmark GMD Vulnerability Assessment to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.
If a recipient of the benchmark GMD Vulnerability Assessment provided documented comments on the results, dated evidence the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) Verify the responsible entity completed the benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60-calendar months.
	(R4) Verify the use of studies to complete the benchmark GMD Vulnerability Assessment based on models evidenced in R2.
	(R4) Verify the benchmark GMD Vulnerability Assessment documented assumptions and summarized results of the steady state analysis.
	(Part 4.1) Verify the study or studies include System On-Peak Load and System Off-Peak Load conditions for at least one year within the Near-Term Transmission Planning Horizon.
	(Part 4.2) Verify the study or studies were conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.
	(Part 4.3) Verify the benchmark GMD Vulnerability Assessment was provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.
	(Part 4.3) Verify the benchmark GMD Vulnerability Assessment was provided to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.
	(Part 4.3.1) If a recipient of the benchmark GMD Vulnerability Assessment provided documented comments on the results, verify the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Note to Auditor: Auditor should consider reviewing Requirement R4 in conjunction with Requirement R7, since the development and review of Corrective Action Plans are corollaries to the benchmark GMD Vulnerability Assessment.	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include:

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Registered Entity Response (Required):
Question: During the audit period, did the entity receive a written request for effective GIC time series, GIC(t), from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area?
☐ Yes ☐ No
If Yes, provide a list of such requests.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
A list of each Transmission Owner and Generator Owner in the planning area that owns an applicable BES power transformer.
Evidence demonstrating the responsible entity provided the maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1 to each Transmission Owner and Generator Owner in the planning area that owns an applicable BES power transformer in the planning area.
Evidence demonstrating the responsible entity, within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1, provided the effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Verify the responsible entity provided GIC flow information to each Transmission Owner and Generator Owner that owns an applicable BES power transformer in the planning area.
	(Part 5.1) Verify the GIC flow information provided by the responsible entity included the maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1.
	(Part 5.2) For all, or a sample of, written requests from applicable Transmission Owner or Generation Owners, verify the responsible entity provided the effective GIC time series, GIC(t), within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall:

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The GIC flow information provided by the Planning Coordinator or Transmission Planner in accordance with Requirement R5.
Dated evidence demonstrating the completion of the benchmark thermal impact assessment for each of the entity's solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A per phase or greater.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) Verify the entity conducted a benchmark thermal impact assessment for each applicable BES power transformer where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater.
	Review thermal impact assessments for applicable BES power transformers and confirm the thermal impact assessment meets the requirements identified in Requirement R6 Part 6.1 through Part 6.4.
	(Part 6.1) Be based on the effective GIC flow information provided in Requirement R5.
	(Part 6.2) Document assumptions used in the analysis.
	(Part 6.3) Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any.
	(Part 6.4) Be performed and provided to the responsible entities as determined in Requirement R1 within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.
Note to Auditor:	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~ERO~~ approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the Compliance Enforcement Authority (CEA)~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Registered Entity Response (Required):
Question: Did the responsible entity conclude through the GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements of Table 1? ☐ Yes ☐ No

If Yes, provide a dated list of CAPs developed to address how the performance requirements will be met.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.
Copy of the benchmark GMD Vulnerability Assessment conducted in Requirement R4
A list of System deficiencies identified through the GMD Vulnerability Assessment.
All dated CAPs associated with the System deficiencies, which identify the associated actions needed to achieve required System performance.

Evidence the CAP was submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3.
Dated evidence that the CAP was provided, within 90 calendar days of development or revision, to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the CAP.
Dated evidence that the CAP was provided to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.
If a recipient of the CAP provided documented comments on the CAP, evidence the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R7

This section to be completed by the Compliance Enforcement Authority

	(R7) Verify the entity developed a CAP addressing how the performance requirements will be met for the steady state planning benchmark GMD event, if the entity concluded through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of Table 1. Verify the CAP:
	(Part 7.1) List system deficiencies and associated actions needed to achieve required System performance.
	(Part 7.2) The CAP was developed within one year of completion of the benchmark GMD Vulnerability Assessment.
	(Part 7.3) The CAP includes a timetable.
	(Part 7.3.1) A timetable specifying implementation of non-hardware mitigation, if any, within two years of development of the CAP.
	(Part 7.3.2) A timetable specifying implementation of hardware mitigation, if any, within four years of the development of the CAP.
	(Part 7.4) Verify the CAP was submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3.

	(Part 7.4.1) Verify the submitted CAP documents circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of each responsible entity.
	(Part 7.4.2) Verify the submitted CAP documents revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable.
	(Part 7.4.3) Verify the submitted CAP documents an updated timetable for implementing the selected actions in Part 7.1.
	(Part 7.5) Verify the responsible entity provided the CAP, within 90 calendar days of development or revision, to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the CAP.
	(Part 7.5) Verify the responsible entity provided the CAP to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.
	(Part 7.5.1) If a recipient of the CAP provided documented comments on the CAP, verify the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Note to Auditor:	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis:

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated copies of the current and preceding supplemental GMD Vulnerability Assessments of Near-Term Transmission Planning Horizon.
Evidence the study or studies include System On-Peak Load and System Off-Peak Load conditions for at least one year within the Near-Term Transmission Planning Horizon.
Evidence the study or studies were conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event in Table 1.
Dated evidence that the responsible entity provided the supplemental GMD Vulnerability Assessment within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners.
Dated evidence that the responsible entity provided the supplement GMD Vulnerability Assessment to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.
If a recipient of the supplemental GMD Vulnerability Assessment provided documented comments on the results, dated evidence the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R8

This section to be completed by the Compliance Enforcement Authority

	(R8) Verify the responsible entity completed the supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60-calendar months.
	(R8) Verify the use of studies to complete the supplemental GMD Vulnerability Assessment based on models evidenced in R2.
	(R8) Verify the supplemental GMD Vulnerability Assessment documented assumptions and summarized results of the steady state analysis.
	(Part 8.1) Verify the study or studies include System On-Peak Load and System Off-Peak Load conditions for at least one year within the Near-Term Transmission Planning Horizon.
	(Part 8.2) Verify the study or studies were conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.
	(Part 8.3) Verify the supplemental GMD Vulnerability Assessment was provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners.
	(Part 8.3) Verify the supplemental GMD Vulnerability Assessment was provided to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.
	(Part 8.3.1) If a recipient of the supplemental GMD Vulnerability Assessment provided documented comments on the results, verify the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Note to Auditor:	

Auditor Notes:

<u>**R9 Supporting Evidence and Documentation**</u>

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include:

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
A list of each Transmission Owner and Generator Owner in the planning area that owns an applicable BES power transformer.
Dated evidence demonstrating the responsible entity provided the maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1 to each Transmission Owner and Generator Owner in the planning area that owns an applicable BES power transformer in the planning area.
Dated evidence demonstrating the responsible entity, within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1, provided the effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request

from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R9

This section to be completed by the Compliance Enforcement Authority

	(R9) Verify the responsible entity provided GIC flow information to each Transmission Owner and Generator Owner that owns an applicable BES power transformer in the planning area.
	(Part 9.1) Verify the GIC flow information provided by the responsible entity included the maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1.
	(Part 9.2) For all, or a sample of, written requests from applicable Transmission Owner or Generation Owners, verify the responsible entity provided the effective GIC time series, GIC(t), within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.
Note to Auditor:	

Auditor Notes:

R10 Supporting Evidence and Documentation

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall:

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The GIC flow information provided by the Planning Coordinator or Transmission Planner in accordance with Requirement R9.
Dated evidence demonstrating the completion of the supplemental thermal impact assessment for each of the entity's solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9 Part 9.1 is 85 A per phase or greater.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R10

This section to be completed by the Compliance Enforcement Authority

	(R10) Verify the entity conducted a supplemental thermal impact assessment for each applicable BES power transformer where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater.
	(R10) Review supplemental thermal impact assessments for applicable BES power transformers and confirm the thermal impact assessment meets the requirements identified in Requirement R10 Part 10.1 through Part 10.4.
	(Part 10.1) Be based on the effective GIC flow information provided in Requirement R9.
	(Part 10.2) Document assumptions used in the analysis.
	(Part 10.3) Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any.
	(Part 10.4) Be performed and provided to the responsible entities as determined in Requirement R1 within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.
Note to Auditor:	

Auditor Notes:

R11 Supporting Evidence and Documentation

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ~~ERO~~ approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. This submission shall include the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and,

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that identifies the roles and responsibilities of entities in the planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessments.
Copy of the supplemental GMD Vulnerability Assessment conducted in Requirement R8
A list of System deficiencies identified through the supplemental GMD Vulnerability Assessment.
All dated CAPs associated with the System deficiencies, which identify the associated actions needed to achieve required System performance.
Evidence the CAP was submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3.
Dated evidence that the CAP was provided, within 90 calendar days of development or revision, to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the CAP.
Dated evidence that the CAP was provided to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.
If a recipient of the CAP provided documented comments on the CAP, evidence the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R11

This section to be completed by the Compliance Enforcement Authority

	(R11) Verify the entity developed a CAP addressing how the performance requirements will be met for the steady state planning supplemental GMD event, if the entity concluded through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that their System does not meet the performance requirements of Table 1. Verify the CAP:
	(Part 11.1) List system deficiencies and associated actions needed to achieve required System performance.
	(Part 11.2) The CAP was developed within one year of completion of the supplemental GMD Vulnerability Assessment.
	(Part 11.3) The CAP includes a timetable.
	(Part 11.3.1) A timetable specifying implementation of non-hardware mitigation, if any, within two years of development of the CAP.
	(Part 11.3.2) A timetable specifying implementation of hardware mitigation, if any, within four years of the development of the CAP.
	(Part 11.4) Verify the CAP was submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3.
	(Part 11.4.1) Verify the submitted CAP documents circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of each responsible entity.
	(Part 11.4.2) Verify the submitted CAP documents revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable.
	(Part 11.4.3) Verify the submitted CAP documents an updated timetable for implementing the selected actions in Part 11.1.
	(Part 11.5) Verify the responsible entity provided the CAP, within 90 calendar days of development or revision, to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the CAP.

	(Part 11.5) Verify the responsible entity provided the CAP to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.
	(Part 11.5.1) If a recipient of the CAP provided documented comments on the CAP, verify the responsible entity provided a documented response to that recipient within 90 calendar days of receipt of those comments.
Note to Auditor:	

Auditor Notes:

R12 Supporting Evidence and Documentation

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model.

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that identifies the implementation of a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model.
Documentation that identifies the roles and responsibilities of entities in the planning area for implementing process(es) to obtain GMD measurement data.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R12
This section to be completed by the Compliance Enforcement Authority

	Verify that the responsible entity, as determined in Requirement R1, implemented its process to obtain

	GIC monitor data.
	Verify that GIC monitor data came from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model.
Note to Auditor:	

Auditor Notes:

R12 Supporting Evidence and Documentation

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that identifies the implementation of a process to obtain geomagnetic field data for its Planning Coordinator's planning area.
Documentation that identifies the roles and responsibilities of entities in the planning area for implementing process(es) to obtain GMD measurement data.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-007-4, R13

This section to be completed by the Compliance Enforcement Authority

	Verify that the responsible entity, as determined in Requirement R1, implemented its process to obtain geomagnetic field data.
	Verify that geomagnetic field data is for the Planning Coordinator's planning area.

Note to Auditor:

Auditor Notes:

Additional Information:

Reliability Standard
<insert final PDF here>
The full text of TPL-007-4 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Regulatory Language <to be updated after approval>
In Order No. 830, issued in 2016, the Federal Energy Regulatory Commission approved Reliability Standard TPL-007-1 and directed further revisions. Specifically, FERC directed NERC to: (1) revise the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data (P 44); (2) make corresponding revisions to Requirement R6, relating to transformer thermal impact assessments (P 65) ; (3) require entities to collect GIC monitoring and magnetometer data (P 88); and (4) include deadlines for the development and completion of Corrective Action Plans to address identified system vulnerabilities (PP 101-102). Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215 (2016).

In response to FERC's Order No. 830 directives, NERC developed Reliability Standard TPL-007-2. Reliability Standard TPL-007-2 added new Requirements for entities to assess their vulnerabilities to a second defined event, the supplemental GMD event. The standard added new Requirements for the collection of GIC and magnetometer data. The standard also revised Requirement R7 to include deadlines for the development and completion of any necessary Corrective Action Plans.

The Commission approved Reliability Standard TPL-007-2 in Order No. 851, issued in 2018. In this Order, FERC also directed further revisions as follows:

1. Require Corrective Action Plans for Supplemental GMD Vulnerability Assessment Vulnerabilities

    29. As proposed in the NOPR, pursuant to section 215(d)(5) of the FPA, we also determine that it is appropriate to direct NERC to develop and submit modifications to Reliability Standard TPL-007-2 to require the development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Given that NERC has acknowledged the potential for "severe, localized impacts" associated with supplemental GMD event vulnerabilities, we see no

basis for requiring corrective action plans for benchmark GMD events but not for supplemental GMD events.[] Based on the record in this proceeding, there appear to be no technical barriers to developing or complying with such a requirement. Moreover, as discussed below, the record supports issuance of a directive at this time, notwithstanding NOPR comments advocating postponement of any directive until after the completion of additional GMD research, because relevant GMD research is scheduled to be completed before the due date for submitting a modified Reliability Standard. The Commission therefore adopts the NOPR proposal and directs NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.

2. Implement Case-by-Case Exception Process for Considering Corrective Action Plan Completion Deadline Extensions

30. We also determine, pursuant to section 215(d)(5) of the FPA, that it is appropriate to direct that NERC develop further modifications to Reliability Standard TPL-007-2, Requirement R7.4. Under NERC's proposal, applicable entities are allowed, without prior approval, to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]."[] Instead, as discussed below, we direct NERC to develop a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-by-case basis. Our directive balances the availability of time extensions when applicable entities are presented with the types of uncontrollable delays identified in NERC's petition and NOPR comments with the need to ensure that the mitigation of known GMD vulnerabilities is not being improperly delayed through such requests. Further, as proposed in the NOPR, we direct NERC to prepare and submit a report addressing how often and why applicable entities are exceeding corrective action plan deadlines as well as the disposition of time extension requests. The report is due within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission will determine whether further action is necessary.

56. In reaching our determination on this issue, we considered NERC's NOPR comments, which attempted to address the concerns with Requirement R7.4 expressed in the NOPR, stating that NERC and Regional Entity compliance and enforcement staff will review the reasonableness of any delay in implementing corrective action plans, including reviewing the asserted "situations beyond the control of the responsible entity" cited by the applicable entity, and by citing specific examples of the types of delays that might justify the invocation of Requirement R7.4. NERC's comments also characterized Requirement R7.4 as being "not so flexible … as to allow entities to extend Corrective Action Plan deadlines indefinitely or for any reason whatsoever."[] We generally agree with the standard of review that NERC indicates it will use to determine whether an extension of time to implement a corrective action plan is appropriate. However, the assessment of whether an extension of time is warranted is more appropriately made before an applicable entity is permitted to delay mitigation of a known GMD vulnerability. While NERC indicates that under proposed Requirement R7.4 there are compliance consequences for improperly delaying mitigation, mitigation of a known GMD vulnerability will nonetheless have been delayed, and we conclude it is important that any proposed delay be reviewed ahead of

time. Therefore, we direct NERC to modify Reliability Standard TPL-007-2, Requirement R7.4 to develop a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-by-case basis.

Order No. 851, *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 165 FERC ¶ 61,124 (2018).

In February 2019, the NERC Board of Trustees adopted a regional Variance for Canadian jurisdictions in Reliability Standard TPL-007-3. None of the continent-wide Requirements were changed. This standard version has been submitted to the Canadian provincial authorities for approval and to FERC for informational purposes only.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	08/02/2019	NERC Compliance, Standards, RSAWTF	New Document
2	11/13/2019	NERC Compliance, Standards, RSAWTF	Updated to most recent draft of the Standard

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Standards Announcement

Project 2019-01 Modifications to TPL-007-3

Ballot Pools Forming through August 26, 2019
Formal Comment Period Open through September 9, 2019

Now Available

A 45-day formal comment period for **TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern, Monday, September 9, 2019.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues using the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, August 26, 2019.** Registered Ballot Body members can join the ballot pools here.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An Initial ballot for the standard, along with non-binding polls for the associated Violation Risk Factors and Violation Severity Levels, will be conducted **August 30 – September 9, 2019.**

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify “Project 2019-01 Modifications to TPL-007-3 Observer List” in the Description Box. For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2019-01 Modifications to TPL-007-3
Comment Period Start Date:	7/26/2019
Comment Period End Date:	9/9/2019
Associated Ballots:	2019-01 Modifications to TPL-007-3 TPL-007-4 IN 1 ST

There were 66 sets of responses, including comments from approximately 133 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

8. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aubrey Short	4		FE VOTER	Ann Carey	FirstEnergy	6	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aubrey Short	FirstEnergy	4	RF
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Bobbi Welch	Midcontinent Independent System Operator	2	MRO
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative	1	WECC

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrianne Collins	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

						Company Generation		
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no NGrid and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
PSEG	Sean Cavote	1,3,5,6	FRCC,NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Jamison Cawley	Nebraska Public Power District	1	MRO

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with replacing the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis. Since R7.4 is for “situations beyond the control of the entity,” it does not matter if the extensions are considered on a case-by-case basis as the entity will not be able to comply with the CAP timeline as the situation was beyond their control. Adding the case-by-case basis would increase the administrative burden to entities while adding very little benefit to the reliability of the BPS.	
Likes 6	Orlando Utilities Commission, 1, Staley Aaron; Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES.

Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation recommends Requirement R7 be phrased in terms of a responsible entity's required action, not an action required by a CAP.

Reclamation also recommends restructuring TPL-007 so that one requirement in TPL-007 addresses corrective action plans for both benchmark and supplemental GMD Vulnerability Assessments. Reclamation offers the following language for this requirement (see the response to Question 2 regarding the numbering):

R10. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 or the Supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met.

10.1. The responsible entity shall develop the CAP within one year of completion of the benchmark GMD Vulnerability Assessment or Supplemental GMD Vulnerability Assessment.

10.2. The CAP shall contain the following:

10.2.1. A list of System deficiencies and the associated actions needed to achieve required System performance.

10.2.2. A timetable, subject to the following provisions, for implementing each action identified in 7.2.1:

10.2.2.1. Any implementation of non-hardware mitigation must be complete within two years of development of the CAP; and

10.2.2.2. Any implementation of hardware mitigation must be complete within 4 years of development of the CAP.

10.3 The responsible entity shall provide the CAP to the following entities within 90 days of development, revision, or receipt of a written request

10.3.1. Reliability Coordinator;

10.3.2. Adjacent Planning Coordinator(s);

10.3.3. Adjacent Transmission Planner(s);

10.3.4. Functional entities referenced in the CAP; or

10.3.5. Any functional entity that submits a written request and has a reliability-related need for the CAP.

10.4. If a recipient of a CAP provides documented comments about the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

10.5. If a responsible entity determines it will be unable to implement a CAP within the timetable provided in part 7.2.2, the responsible entity shall:

10.5.1. Document the circumstances causing the inability to implement the CAP within the existing timetable;

10.5.2. Document the reason those circumstances prevent the timely implementation of the CAP (including circumstances beyond the entity's control);

10.5.3. Document revisions to the actions identified in part 7.2.1 and the timetable in part 7.2.2; and

10.5.4. Submit a request for extension of the revised CAP to the ERO.

Regarding R10.2.2, Reclamation recommends against mandating industry-wide timelines due to the differences in each entity's capabilities to meet deadlines. For example, the differences in procurement processes and timelines among entities.

Regarding R10.5, Reclamation recommends the standard describe an extension policy. Regional entities may not be capable of fully researching the entire interconnection in order to provide adequate approvals. Reclamation recommends the regional entities or the ERO automate the CAP tracking process.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

Please see comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI supports the language in Requirements R7.3 and R7.4 believing the proposed changes meet the intent of Order 851. However, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs additional details to ensure efficient processing of entity CAP Extension Requests, including:

1. A process flow diagram documenting the CAP Extension Process and roles and responsibilities of participants, including the ERO and its authority in this process.

2. NERC contact information where companies can quickly and efficiently check the status of their CAP Extension Requests.

3. Defined deadlines for the completion of CAP Extension Request reviews by NERC and responding to entity inquiries.

4. A process for extending a CAP review deadline for situations where NERC may need additional time.

5. Criteria for a CAP Extension Request

6. An appeals process for denied CAP Extension Requests.

7. A formal process to notify entities on the final ruling for all CAP Extension Requests.

8. Identification of who has oversight of the process within the ERO.

While EEI recognizes that the SDT is still early in the development phase of the TPL-007-4 Reliability Standard, we believe it is important to emphasize that having a strong CAP Extension Request process is crucial to ensuring that the directed CAPs are effectively and efficiently processed, similar to the BES Exceptions Process (see Rules of Procedure, Appendix 5C; Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System).

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

Exelon agrees with EEI’s comments. Exelon believes that the SDT has proposed changes to Requirements R7.3 and R7.4 that meet the intent of the FERC directive in Order 851 but feel it requires further modifications. The Draft TPL-007-4 CAP Extension Request Review Process does not provide the requesting entity with a clear understanding of how the request will be considered, when a decision can be expected, and how an entity could request reconsideration if an extension is denied. With the FERC directive requiring ERO involvement in this case, this justifies placing an obligation on the ERO. The development of a well-defined process similar to the Technical Feasbility Exception Process or the BES Exceptions Process should be concurrently developed and submitted along with the proposed standard to facilitate NERC’s engagement. This will provide a mechanism to address the key items noted in EEI’s comments.

On Behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 1 by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE

Answer	No
Document Name	

Comment

This requirement gives responsibility to an entity which is not an applicable entity under the Standard. The requirement as written also has no impact on reliability, it is purely an administrative requirement and does not directly provide the entitiy with an approved extension. There should be a requirement added which requires the entity that receives the request for CAP extension approve the request within a specified timeframe.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the modifications to R7.4 meet the directive in FERC Order. No. 851 by replacing the corrective action plan time-extension provisions in R7.4 with a process that extensions of time are considered on a case-by case basis.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment
Yes, the proposed TPL-007-4 Requirement R7, Part 7.4 meets the directive of FERC Order No. 851, Paragraph 54. The FERC directive is extremely narrow and the Project 2019-01 SDT has met the intent to require a process to consider time extensions on a case-by-case basis. However, the FERC directive did not demand that the ERO be the adjudicating entity for time extensions and we suggest the following revision to each ERO reference in the proposed TPL-007-4: "ERO, or its delegated designee." We believe that this modification will allow Regional Entities or other designees to better adjudicate CAP time extensions given their closer proximity, System expertise, and existing Compliance Program obligations.

Likes 1	Orlando Utilities Commission, 1, Staley Aaron
Dislikes 0	

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	

Comment
Do you agree that R7 meets the directive? my possible answer is NO. **Please see EEI's comments**

Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes

Document Name	
Comment	
The proposed language meets the FERC directive.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA understands that the SDT had to respond with proposed changes to meet the directive for R7. BPA does not agree that entities should have to request approval from the ERO for an extension to the Corrective Action Plan for circumstances that occur beyond the entities control. BPA would like to utilize the new ERO Portal tool to allow NERC and the Commission immediate access in real time to the corrective action plan extensions and the justification for the extension. Retaining the requirement as written gives entities the flexibility to respond to unanticipated circumstances without the administrative burden of seeking an extension from NERC. NERC and the Commission would be able to determine if entities are abusing this flexibility and if abuse occurs, should seek to remedy at that time.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
I agree that the language meets the directive, but would it make more sense for the standard to assign this to the regional entities instead of the ERO?	
Likes 0	
Dislikes 0	

Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Agree that R7 meets the directive. Do not agree that Part 7.4 should require the request for extension be submitted to the ERO for approval. It makes more sense the request be submitted to the Regional Entity.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the modification of Requirement R7.4 to meet the directive of Order No. 851. However, Eversource does note that the proposed R7 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	

Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	Project 2019-01 Comment Form Attachment.docx
Comment	

ISO/RTO Council Standards Review Committee members ERCOT, MISO, NYISO, PJM, and SPP (the "SRC") submit the following comments regarding Project 2019-01 Modifications to TPL-007-3.

The SRC agrees that the revisions to Requirement R7 proposed by the SDT satisfy FERC's directive in Order 851 regarding extensions of time to implement corrective action plans on a case-by-case basis. In order to further streamline Requirement R7 and more closely align Requirement R7 to the specific language in FERC's directive, the SRC offers the proposed revisions described below and identified in the attached for consideration by the SDT.

In connection with Part 7.3, mentioning the ERO approval processes is not necessary given that Part 7.4 addresses the process. Deleting the reference ("ERO approval for any extension sought under") would result in a more streamlined requirement, and would more closely align with FERC's directive that *Part 7.4* be modified to incorporate the development of a timely and effective extension of time review process. This proposed revision to the current draft of Part 7.3 proposed by the SDT is identified in the attached redline.

In connection with Part 7.4, the SRC suggests the SDT consider:

1. Including express language that an extension of time is “subject to the approval of NERC and the reliability entity’s Regional Entity(s) on a case-by-case basis” in order to more closely align Part 7.4 with FERC’s specific directive that Part 7.4 be modified and that requests for extension of time are to be reviewed on a “case-by-case basis.”

2. Utilizing “NERC and the reliability entity’s Regional Entity(s)” instead of “ERO” in order to more closely align with the specific language utilized in Order 851.

3. Including “of time” in order to more clearly articulate what type of extension is available under Part 7.4

These proposed revisions to the current draft of Part 7.4 proposed by the SDT are identified in the attached redline.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the standard drafting team's (SDT) efforts to meet the FERC directives. Texas RE has a few concerns as to how the SDT approached the directives.

First, Texas RE is concerned with the following language in Part 7.4:

Additionally, Texas RE is concerned with the ERO's role involving the process for granting CAP extensions. Texas RE asserts that it may be more appropriate to keep operational aspects of the BPS within the hands of the owners/operators and simply make the ERO aware of the CAP. For example, Texas RE suggests that the RC is the appropriate entity to accept/approve the extensions for CAPs. In addition, there could also be a requirement for the registered entity to inform its CEA of a CAP extension. This way, the ERO can verify compliance as far as the RC reviewing extensions of the CAPs and the ERO would not become part of the compliance evaluation and processes of the standard by not having to verify that they themselves reviewed the CAP extension. Moreover, this is consistent with Reliability Standard PRC-012-2 Requirement R6, which requires the RAS-entity submit the CAP to its reviewing RC as the RC has the relevant expertise to review the CAP.

- Part 7.4.1 requires entities to document how circumstances causing delay are beyond the control of the responsible entity, but Part 7.4 does not include language to specify that an extensions are only allowed when “situations beyond the control of the responsible entity [arise].” (FERC Order No. 851). Texas RE recommends updating Part 7.4 to include requirements for extension so implementation issues do not get categorized as documentation issues under Part 7.4.1.
- Part 7.4 only specifies that CAP extensions shall be submitted but does not include language requiring that CAP extensions be approved. While the Draft TPL-007-4 CAP Extension Request Review Process, which is outside of the requirement language, sates “All CAP extension requests must be approved the ERO Enterprise prior to the original CAP completion date”, it may be helpful to specify the timetables for extension requests in relation to the timetables for implementation in the original CAP to avoid scenarios in which the responsible entity submits an extension request immediately prior to the planned implementation date.
- Neither the requirement nor the Draft TPL-007-4 CAP Extension Request Review Process indicate what shall occur if a CAP extension request is not approved.
-

Likes 0	
Dislikes 0	

Response

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Comment is the same as question #1.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 2 by the Edison Electric Institute.

Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon agrees with EEI's comments and believes that the same concerns expressed in the response to Question 1 are applicable to R11 as well. On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA supports comments submitted by AEP for Question #2.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports the language in Requirements R11 believing the proposed changes meet the intent of Order 851. However as stated in more detail in our response to Question 1, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs to include additional details to ensure effective and transparent processing of entity CAP Extension Requests.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	

Comment
Please see comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	

Comment
PSEG supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	

Comment

Reclamation recommends combining the TPL-007 CAP requirements in R7 and R11 as provided above in response to Question 1. If Reclamation's proposal is accepted, Reclamation recommends restructuring and renumbering the requirements in TPL-007 as follows:

R1 through R6 – no change

R7 – remove and combine CAP language with existing R11

R8 – renumber existing R8 to R7

R9 – renumber existing R9 to R8

R10 – renumber existing R10 to R9

R11 – combine CAP language from existing R7; renumber the new single CAP requirement to R10

R12 – renumber existing R12 to R11

R13 – renumber existing R13 to R12

This will improve the logical flow of the activities required by the revised standard. Reclamation also recommends the SDT add a heading between the new M9 and R10 for "Corrective Action Plans" for consistency with the existing headings "Benchmark GMD Vulnerability Assessments" between M3 and R4, "Supplemental GMD Vulnerability Assessments" between M7 and R8, and "GMD Measurement Data Processes" between M11 and R12.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

ACES believes that the directive could have been dealt with in a less onerous way that addresses concerns other entities have expressed, in their comments, about the potential for duplication of effort between the baseline corrective action plans and supplement corrective action plans. To alleviate some of that potential, the standard could expressly state that corrective action plans are only required for supplemental GMD Vulnerability Assessments, if the corrective actions plans identified for the baseline GMD Assessments do not already address any additional vulnerabilities identified by the supplemental GMD Assessments.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No

Document Name	
Comment	

Comments: NIPSCO does not agree with the Requirement R11 that requires development and implementation of Corrective Action Plan (CAP) for Supplemental GMD events. Judging by the reference geoelectric field values to be utilized for the Supplemental event, the effort appears to be duplicative of the benchmark GMD event (8V/km) with a higher magnitude of 12V/km. As such, we believe the supplemental event represents an “extreme” version of a case that will be assessed under the defined benchmark event.

As corrective action plans are to be developed and implemented for the benchmark GMD event(Requirement R7), requiring CAP for Supplemental event will unnecessarily burden companies for cases that represents an extreme system condition and is not the best cost effective approach to meet the FERC directive

Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	
Comment	

See question one.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

See EEI's comments.

Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	

CHPD does not agree with requiring the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Entities have only just begun the process of evaluating the benchmark GMD event and developing mitigation measures. The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While some aspects of R11 may indeed meet the directives as ***literally*** stated in Order No. 851, we do not believe it is a prudent way to meet the ***spirit*** of those directives. We believe R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and disagree with its inclusion. In addition, the obligation to "specify implementation" of mitigation may not be consistently interpreted among entities, and as a result, may not meet the directives for reasons we will provide in this response.

It is our view that the original purpose of the supplemental event was to investigate the impact of local enhancement of the generated electric field from a GMD event on the transmission grid. This requires industry to take an approach in which the GICs are calculated with the higher, enhanced electric field magnitude of 12 V/km (adjusted for location and ground properties) applied to some smaller defined area while outside of this area the benchmark electric field magnitude of 8 V/km (also adjusted for location and ground properties) is applied. This smaller area is then systematically moved across the system and the calculations are repeated. This is necessary as the phenomenon could occur anywhere on the system. Using this Version 2 methodology, every part of the system is ultimately evaluated with the higher electric field magnitude.

In our view, the supplemental event represents a more extreme scenario. Referring to Attachment 1 of the proposed standard, the section titled '**Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event**' provides examples of applying the localized peak geoelectric field over the planning area. The first example presented is applying the peak geoelectric field (12 V/km scaled to planning area) over the entire planning area. This example is a more severe condition than the benchmark event, and should alleviate the need to study the benchmark event if used. In addition, modeling tools for conducting GMD vulnerability studies for the supplemental event using the moving box method have not yet been developed. As such, adding a corrective action plan requirement to the supplemental event obviates the need for studying the benchmark event. Rather than pursuing a Corrective Action Plan for the existing Supplemental GMD Vulnerability Assessment, we believe the SDT should instead pursue only one single GMD Vulnerability Assessment using a reference peak geoelectric field amplitude not determined solely by non-spatially averaged data. This would be preferable to requiring two GMD Vulnerability Assessments, both having Corrective Action Plans and each having their own unique reference peak geoelectric field amplitude. When the Supplemental GMD Vulnerability Assessment was originally developed and proposed, there was no CAP envisioned for it. Because of this, one could argue the merits of having two unique assessments, as each were different not only in reference peak amplitude, but in obligations as well. What has now been proposed in this revision however, is essentially having two GMD Vulnerability Assessments requiring Corrective Action Plans but with different reference peak geoelectric field amplitudes (one presumably higher than the other). It would be unnecessarily burdensome, as well as illogical, to have essentially the same obligations for both a baseline and supplemental vulnerability assessment. In addition to its duplicative nature, it is possible that the results from a benchmark study may even differ or conflict with the results from a given supplemental study.

While the NOPR directs the standard to be revised to incorporate the "development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities", we find rather that R11 requires the entity "specify implementation" of mitigation. This could be interpreted by some as simply specifying what actions are to be taken but without explicit bounds or expectations on when the final execution of that implementation (i.e. "completion") would take place.

Once again, we believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude for a single GMD Vulnerability Assessment (benchmark), one not determined solely by non-spatially averaged data, and that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES.

Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	Yes
Document Name	

Comment

The SRC agrees that adding Requirement R11, which is based on the existing language of Requirement R7, satisfies FERC's directive in Order 851 regarding the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. To the extent the SDT incorporates in Requirement R7 the SRC's suggested revisions identified in response to Question No. 1 above, the SRC proposes the SDT make the same revisions to Requirement R11.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the addition of Requirement R11 to meet the directive of Order No. 851. However, Eversource does note that the proposed R11 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The SDT has met the directive in Order 851. BPA understands that the SDT had to respond with proposed changes to meet the directive for R11. BPA would like to reiterate the industry's and NERC's opposition to developing corrective action plans for an extreme event (Supplemental GMD event) and the similarity to TPL-001-4. A GMD event is considered to be a one in one hundred year event. BPA believes that assessing the event and performing an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan. BPA supports the comments made by NERC, referenced in FERC's Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines	

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC's comments reiterate the rationale in its petition that requiring mitigation "would result in the de facto replacement of the benchmark GMD event with the proposed supplemental GMD event." **39** NERC maintains that "while the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis of requiring Corrective Action Plans."**40** NERC also claims that the uncertainty of geographic size of the supplemental GMD event could not be addressed adequately by sensitivity analysis or through other methods because there are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) … [and] introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."**41**

39 *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area").

40 *Id.* at 13.

41 *Id.* at 15.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

The proposed language meets the FERC directive.

Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Do you agree that R11 meets the directive? my possible answer is NO. **Please see EEI's comments**	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirement R11 meets the directive of FERC Order No. 851, Paragraph 39. Again, the FERC directive leaves little room for flexibility, requiring CAPs for the supplemental GMD event. While we are disappointed that FERC was not persuaded by the technical challenges of simulating locally-enhanced peak geoelectric field suitable for supplemental GMD event analysis, the Project 2019-01 SDT has met the intent.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R11 meets the requirements in FERC Order 851. The modifications to R11 properly address Order 851's requirement to develop CAP to mitigate assessed supplemental GMD event vulnerabilities with provisions for extension of time on a case-by-case analysis.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE's comments regarding Part 7.4 in question #1 as they also apply to Part 11.4.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	

PSE will abstain from answering this question

Likes 0	
Dislikes 0	

Response

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
N/A	
Likes 1	Western Area Power Administration, 6, Jones Rosemary
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The Canadian variance does not completely reflect the unique regulatory process in each region in Canada. The Manitoba Hydro Act prevents adoption of reliability standards that have the effect of requiring construction or enhancement of facilities in Manitoba. Manitoba Hydro modified the language of TPL-007-2 that works in Manitoba.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	

Response

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the Canadian variance portion of the standard is helpful for the utilities in the United States. However, SCL cannot comment on the language of the standard in the Canadian Variance portion where it relates to regulatory process in Canada.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP is not impacted by the Canadian variance..	
Likes 0	
Dislikes 0	
Response	

Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
For the parts of the proposed changes to R7 (new R10) stated in the response to Question 1 that are accepted, Reclamation recommends conforming changes be made to the pertinent language in the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource has no opinion on the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes

Document Name	
Comment	

MISO supports the comments submitted by the IRC SRC.

Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	Yes
Document Name	
Comment	

The Canadian member of the SRC agrees that the Canadian variance is written in a way that accommodates the regulatory process in Canada.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	
Document Name	
Comment	
Not applicable to FirstEnergy.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
CHPD defers the response to this question to the Canadian provinces to determine if the Canadian variance is written to accommodate the regulatory processes in Canada.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	

Answer	
Document Name	
Comment	
GTC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
PSE will abstain from answering this question	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	
Document Name	

Comment	
GSOC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.
Likes 0
Dislikes 0
Response
David Jendras - Ameren - Ameren Services - 3
Answer
Document Name
Comment
Ameren agrees with and supports EEI comments.
Likes 0
Dislikes 0
Response
Bette White - AES - Indianapolis Power and Light Co. - 3
Answer
Document Name
Comment
IPI is not in the Canadian district
Likes 0
Dislikes 0
Response
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE
Answer
Document Name
Comment
N/A

Likes 0	
Dislikes 0	
Response	

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 4 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
As discussed in the response to Question 1, Exelon agrees that changes in Requirements R7, R8 and R11 meet the intent of the FERC directives, but without a clear CAP Extension Process the changes cannot be supported at this time.	

On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
See response to Q2 above.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the language in Requirements R7, R8 and R11 as proposed by the SDT believing that the changes conform to the directives contained in Order 851. Nevertheless, we cannot support these changes as sufficient or complete at this time until a CAP Extension Request Review Process is develop that ensure that key elements, as articulated in our response to Question 1, are addressed.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Please see comments submitted by EEI.	

Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends the language in Requirements R7 and R11 be combined into a single requirement addressing corrective action plans. Please refer to the proposed language provided in the responses to Questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with the directives in FERC Order No. 851 for “Corrective Action Plan Deadline Extensions” or “Corrective Action Plan for Supplemental GMD Event Vulnerabilities” (see responses to questions 1 and 2). Therefore, CHPD does not agree the standard language changes in Requirement R7, R8, and R11 proposed by the SDT.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	
The SRC agrees that the revisions to Requirements R7, R8, and R11 substantially satisfy FERC’s directives articulated in Order No. 851, and refers the SDT to the comments provided in response to Question Nos. 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The SDT has met the directive in Order 851.

BPA understands that the SDT had to respond with proposed changes to meet the directive. BPA believes requiring a corrective action plan for a Supplemental GMD Event is unreasonable and imposes an unnecessary burden on transmission owners and operators.

BPA believes that mitigation strategies for GMD events and the ensuing geomagnetically induced currents would likely be considered novel and in the Research and Development or prototype stages. As such, most devices or control/relay schemes that might be part of a corrective action plan could increase operational complexity and a potential loss of system security. While attempting to mitigate the risk from a low frequency benchmark GMD event, additional risk may be introduced which results in a net reduction in system security. Hence, there is caution from utilities and the industry in general about mandating corrective action plans for schemes and devices that are not well developed and commonly deployed.

BPA supports the comments made by NERC, referenced in FERC's Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC's comments reiterate the rationale in its petition that requiring mitigation

"would result in the de facto replacement of the benchmark GMD event with the

proposed supplemental GMD event." **39** NERC maintains that "while the supplemental

GMD event is strongly supported by data and analysis in ways that mirror the benchmark

GMD event, there are aspects of it that are less definitive than the benchmark GMD event

and less appropriate as the basis of requiring Corrective Action Plans."**40** NERC also

claims that the uncertainty of geographic size of the supplemental GMD event could not

be addressed adequately by sensitivity analysis or through other methods because there

are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation

grounding grid resistance values, transformer thermal and magnetic response models) …

[and] introducing additional variables for sensitivity analysis, such as the size of the

localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."**41**

39 *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments,

which would be to apply extreme peak values uniformly over an entire planning area").

40 *Id.* at 13.

41 *Id.* at 15.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

The proposed language meets the FERC directive.

Likes 0	
Dislikes 0	

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	

Comment

my possible answer is NO.

Please see EEI's comments

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	
Comment	

Yes, the proposed TPL-007-4 Requirements R7, R8, and R11 meets the directives of FERC Order No. 851.

However, FERC has not mandated the specific timetable proposed in Requirement R11, Part 11.3. Considering the 150% geoelectric field enhancement reflected by the supplemental GMD event over the benchmark GMD event, we suggest that the Project 2019-01 SDT modify Requirement R11, Parts 11.3.1 and 11.3.2 to three and six years, respectively.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.

Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC

Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R7, R8, and R11 properly address the requirements in FERC Order 851 as noted under 1 and 2 above.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Please see Texas RE's answer to #1.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	

Comment
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.

Likes 0	
Dislikes 0	

Response

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	No
Document Name	
Comment	
No comments on the modified VRF/VSL for Requirements R7, R8 and R11	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	

Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SCL agrees with the descriptions of VRF/VSL in the standard for requirements R7, R8, and R11.

Likes 0	
Dislikes 0	

Response
Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	Yes
Document Name	

Comment
Reclamation recommends combining R7 and R11. For consistency, Reclamation also recommends the VRF/VSL for these requirements be combined.

Likes 0	
Dislikes 0	

Response
Steve Arnold - City of Independence, Power and Light Department - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Continuing with a previous standard's implementation plan causes confusion, misunderstandings, and the increased potential for missed deadlines. Reclamation recommends retiring the implementation plans for previous versions of TPL-007 and creating a new implementation plan for TPL-007-4 so there is only one implementation plan to work toward.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The implementation plan is likely long enough but does it make sense to have a standard in place that won't be effective for several years? Based on Canadian Law, when a standard is adopted it becomes immediately effective.	
Likes 0	

Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

CHPD does not agree with requiring a CAP for supplemental GMD event (TPL-007-4 R11). Therefore, CHPD does not agree with the implementation plan which requires compliance with R11.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment
Yes, the proposed TPL-007-4 Implementation Plan is consistent; essentially no TPL-007-3 Compliance Dates are changed, except for the modified Requirements R7 and R11 (Requirement R8 proposed changes are trivial). Given the expectation of a rapid FERC approval process, the 01 January 2024 Compliance Dates to develop corrective actions for the supplemental GMD event are reasonable.

Likes 0	
Dislikes 0	

Response
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment
SRP has no comments for the standard drafting team.

Likes 0	
Dislikes 0	

Response
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment
None.

Likes 0	
Dislikes 0	

Response

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees with the impmentation plan for R7, R8, and R11. However, SCL would like to see a later effective date for R12 and R13 or clear guidelines on how to monitor and collect GIC from at least one GIC monitor located in the Planning Coordinator’s area.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that TPL-007-3 is incorrectly referenced on page 1 of the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

TPL-007-4, in contrast to the majority of standards established by NERC, GMD Vulnerability Assessments are not representative of an existing utility practice. This is highlighted by the fact that there is a deficit of modeling tools available that would enable an entity to comply with the requirements specified herein. The burden of expenses relative to CAPs has yet to be established because there are very few examples of vulnerability assessments that have been completed for either the benchmark or the supplemental GMD events. In essence, the science to prudently study and assess system vulnerabilities related to a High Impact, Low Frequency (HILF) event on the system is not conclusive and still subjective. In short, the obligations have come before the development of proven modeling tools and mitigation techniques. Once again, AEP believes that R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and as such, we do not believe it to be cost effective. Those resources would be better served for efforts having a discernable, positive impact on the reliability of the BES. Rather than pursuing this course, we believe a more prudent path, as well as a more cost effective path, would be as we propose in our response to Q1.

Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

No, we do not agree that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner; the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are too short thereby escalating costs. We echo industry comments made during previous modifications to TPL-007-1: FERC opened the door for NERC to propose alternatives to the two- and four-year implementation of corrective actions (FERC Order No. 830, Paragraph 97); FERC was clearly persuaded by device manufacturers over the concerns of utility commenters that mitigation deadlines were impractical (FERC Order No. 830, Paragraph 102). This was particularly problematic because the hardware solutions that existed then, as well as today, remain widely unproven (only one implementation in the continental United States) and are simply not suitable for highly networked Systems (blocking GICs pushes the problem onto neighbors). Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Reliability Coordinator (RC), not the ERO. The RC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek RC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the RC for approval. This is a more appropriate and cost-effective approach to addressing the requests.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	

Answer	No
Document Name	
Comment	

The proposed changes mandates implementation of a Corrective Action Plan for the supplemental GMD event (12 V/km). The research into this type of disturbance is still evolving. The available tools do not support studying this disturbance at this time. The tools available would allow for a uniform field over the entire planning Coordinator area. If this field is increased from 8 V/km to 12 V/km that corresponds to a disturbance well in excess of the 1/100 year level suggested by the benchmark. This is not just and reasonable. Let TPL-007-2 run through its first cycle of studies and review the assessment results. Perhaps the next cycle of studies could evolve to the proposed wording in TPL-007-4 once the research and tools have matured and an assessment of the potential costs have been tabulated to address the supplemental event.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

See EEI's comments.

Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5

Answer	No
Document Name	
Comment	

It is difficult to assess the exact financial impacts of the requirements in this standard. The addition of CAP for Supplementary GMD event may or may not be cost effective.

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees that the SDT satisfied its obligation to modify TPL-007 to meet the directives in FERC Order No. 851. BPA can not determine if the directives are cost effective. The modifications are requiring a corrective action plan for an extreme event (Supplemental GMD event). The Transmission Planners and Transmission Owners have not done the analysis to determine the impact and the cost of the corrective action plans that would be required. BPA believes without this analysis, the cost effectiveness can not be determined. BPA believes that assessing the event and performing an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
We are concerned the cost and effort to address this standard could hinder other more important Transmission improvements.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Comments: See comments on Question 2	
Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
If unintended duplication of efforts between baseline and supplemental corrective action plans occurs, as referenced in the response to question 2, that would lead to unnecessary increases in costs to registered entities. Please reference the suggestion in our response to question 2.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
For the implementation of numerous, overlapping versions of the same standard (such as the implementation of TPL-007-2, TPL-007-3, and TPL-007-4) with lengthy phased-in implementation timelines, Reclamation supports the incorporation of insignificant subsequent modifications (such as the changes from TPL-007-2 to TPL-007-3 to TPL-007-4) in accordance with existing phased-in implementation milestones, but recommends that all previous implementation plans be retired so that there is only one implementation plan in effect at a time.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) has no concerns to cost effective issues from a Planning Coordinator (PC) perspective, however, from the SPP membership perspective, the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are short, thereby escalating costs over two and four years. This timeframe could create issues for hardware solutions.	

Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.

Likes 0	
Dislikes 0	

Response
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment
TVA supports comments submitted by AEP for Question #7

Likes 0	
Dislikes 0	

Response
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO

Answer	No
Document Name	

Comment
Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Planning Coordinator (PC), not the ERO. The PC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek PC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the PC for approval. This is a more appropriate and cost-effective approach to addressing the requests.

Likes 0	
Dislikes 0	

Response
Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees; however, it is difficult to assess the true financial impacts of the requirements in this standard to SCL at this early stage. The modifications in the standard may or may not be cost-effective to SCL.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

NERC should evaluate the relative event probabilities with respect to the cost/benefit analysis of GMD event mitigations. Planning for increasingly rare system events is inherently at odds with economic planning and rate payer responsibilities.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
More experience with implementing the standard is required in order to better understand the implications on its cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.

Likes 0	
Dislikes 0	

Response
David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment
Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	
Document Name	

Comment
No response.

Likes 0	
Dislikes 0	

Response

8. Provide any additional comments for the standard drafting team to consider, if desired.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	
Document Name	
Comment	
Nothing further	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	
Document Name	
Comment	

In Requirements R7 and R11, the SRC suggests replacing “their” with “its” just prior to the first mention of “System” for grammatical reasons.

Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	
Document Name	
Comment	

MISO supports the comments submitted by the IRC SRC. In addition, MISO would like to propose a clarification to requirement R6, part 6.4.

As written, the Transmission Owner and Generator Owner functions referenced under TPL-007-4, requirement R6, Part 6.4 are not functions that are included in the identification of the individual and joint responsibilities under TPL-007-4, requirement R1. As a result, when the Planning Coordinator, in conjunction with its Transmission Planner(s) identifies the individual and joint responsibilities, the Transmission Owner and Generator Owner are not party to this information and so would not know who to provide the results to.

In addition, there is no provision under R1 that requires the Planning Coordinator to determine or communicate who applicable Transmission Owners (section 4.1.3) and Generator Owners (section 4.1.4) within its area should send the results of their benchmark thermal impact assessment to.

MISO became aware of this gap following an inquiry from a transformer owner when they did not know where to send the results.

Possible remedies:

1) Modify Requirement R6, Part 6.4 to reference Requirement 5, i.e. “Be performed and provided to the responsible entity(ies) ***that provided the GIC flow information in accordance with Requirement 5***, within 24…

2) Clarify the scope of requirement Require R1 to specify that the Planning Coordinator in conjunction with its Transmission Planner(s) determine which responsible entity(ies) applicable Transmission Owner(s) and Generator Owner(s) in their area should send the results of their benchmark thermal impact assessment(s) to.

Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO

Answer	
Document Name	
Comment	

The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don't use CMEP Implementation Guidance to establish requirements which go beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following:

• "The local geoelectric field enhancement should not be smaller than 100 km.."- this threshold value of 100 km does not appear in the standard requirement

• "…at a minimum, a West-East orientation should be considered when applying the supplemental event"- the standard requirement does not contain any wording of a minimum consideration

• "Geoelectric field outside the local enhancement:

a. Amplitude: should not be smaller than 1.2 V/km…" This also does not appear in the standard.

• "The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event". This statement creates boundaries outside of requirements, which guidance cannot do

The use of "shall" or "must" should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional "requirement".

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	
Document Name	
Comment	
Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 8 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that TPL-007-4 be consistent with other standards that require data to be submitted from the applicable entities to the Regional Entity. Reliability Standards FAC-003-4, EOP-008-2 Requirement R8, and PRC-002-2 Requirement R12 explicitly state the data shall be submitted to the Regional Entity in the requirement language or in Part C. Compliance section of the standard. There is no need for an extraneous process document describing where to submit the information. Texas RE is concerned with introducing a separate process document for submitting CAP extension requests for the following reasons: the document would not be FERC approved, how would entities and regions know that it exists, where would it be housed, etc. Registered entities should not have to look beyond the standard in order to understand how to comply with a requirement.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

- R7.1 (page 6 of TPL-007-4 clean draft):
    - The portion of this sub-requirement starting from “Examples include:” should be moved to the Implementation Guidance, as the bullet point list’s purpose is more in line with the stated purpose of the Guidance. Consider updating R11.1 as well.
    - To this end, Page iii of Implementation Guidance Document needs to be updated to reflect new SERC region.
- Consider deleting the four references to Attachment 1 in the Draft Technical Rationale document (Draft Tech Rationale_TPL-007-4.pdf).

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Entergy supports comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI acknowledges and supports the good work by the SDT in support of this Reliability Standard believing that it conforms to the directives issued in FERC Order 851. We also recognize that the supporting/companion ERO process document simply represents an initial draft of the Extension Request Process. Nevertheless, the process of CAP extention reviews and approvals are inextricably tied to the modification of this standard. For this reason and as stated in more detail in our response to Question 1, this companion process document needs to include additional details to ensure effective and transparent processing of entity CAP Extension Requests. The process should also be formally codified in parallel with the required revisions to this Reliability Standard.

Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	
Document Name	
Comment	
With the change that the Benchmark and Supplimental analysis both require a CAP, shouldn't they be consolidated into a single study effort to reduce the overall number of requirements? The Supplimental seems to only be a Benchmark with additional areas of increased field strength, unless I am missing some nuiance in how they are performed?	

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	
Document Name	

Comment

What was the rationale behind removing the Supplemental Material? It provided some background information and sources that could be useful for understanding the practicality of the requirement.

Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	

Comments:

1. The language in Requirement 7.4 doesn’t properly align with the FERC Directive on who should be approving the extensions. The FERC directive doesn’t clearly state that the ERO should be the entity approving the extension. We recommend the drafting team consider revising their proposed language to include “ERO, or its delegated designee.” This modification will allow regional entities or other designees to better adjudicate CAP time extensions given their close proximity, System expertise, and existing compliance program obligations.

2. The proposed language in Requirement R11 Part 11.3 doesn’t align with the FERC directive in reference to the duration of the Implementation of the CAP. The FERC directive doesn’t clarify a specific time frame pertaining to the Implementation of the CAPs. Recommend the drafting team consider revising their proposed language for Requirement R11.3 Parts 11.3.1 and 11.3.2 to include an implementation timeframe of three (3) and six (6) years respectively.

3. The SSRG recommends that the drafting team considers including more technical language in the Technical Rationale document, explaining how/why the drafting team came to their conclusions to revising these particular requirements. The document doesn’t provide technical reasoning the drafting team developed or revised this requirement. Chapters 7, 8, and 11 are general, and have no technical information explaining the drafting team’s actions.

4. The SSRG recommends the drafting team consider implementing all the redlines changes to the RSAW that have been identified in the other documents to promote consistency throughout their documentation process.

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

ReliabilityFirst has identified a change in Requirement R1 that was not captured in the redline. When Requirement R1 was copied over to TPL-007-4, the SDT dropped the word “area” from the requirement. As is, the Requirement does not seem to make sence. Please note (in bold text) the updated requirement below:

Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning ***area*** *for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.*

Likes 0	
Dislikes 0	

Response

Andrea Barclay - Georgia System Operations Corporation - 3,4

Answer	
Document Name	

Comment

The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	

Comment

Thank you for the opportunity to comment. ACES appreciates the efforts of drafting team members and NERC staff in continuing to enhance the standards for the benefit of reliability of the BES.

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3,4

Answer	

Document Name	
Comment	
The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
ISO-NE believes that the additional guidance provided in chapter 8 of the draft Transmission System Planned Performance for Geomagnetic Disturbance Events Implementation guidance document for simulating the supplemental GMD event is very helpful. ISO recommends reviewing the language in that chapter to ensure consistency with the purpose of the implementation guidance document as explained in the first paragraph of its Introduction section (i.e. make clear that the information provided describes an example of how the standard's requirements could be met), and not infer the introduction of additional requirements which would not otherwise be contained in the TPL-007 standard.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	
Document Name	
Comment	
The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC to regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES.	

Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Steven Dowell - Alcoa - Alcoa, Inc. - 7	
Answer	
Document Name	
Comment	
Alcoa would like to abstain. Alcoa would urge the SDT to examine cost/benefit analysis for implementation of GMDs at non-critical facilities.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	

The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See EEI's comments.

Likes 0	
Dislikes 0	

Response

James Mearns - Pacific Gas and Electric Company - 1,3,5

Answer	
Document Name	

Comment

As inverter based sources of generation increase on the grid, the requirements of IEEE-Std-519 related to THD percentages (to the 40th harmonic) may need to be revisited. Energy at higher order harmonic frequencies has been observed at bulk (>20 MW) solar sites, which may increase potential for thermal saturation in banks that would otherwise not be susceptable to GIC. Although separate from the specific guidance in this TPL, this may represent a sensitivity factor that could be weighted as part of the overall security assessment of the banks being reviewed.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	
Document Name	

Comment
The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don't use CMEP Implementation Guidance to establish requirements which go beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following: • "The local geoelectric field enhancement should not be smaller than 100 km..”- this threshold value of 100 km does not appear in the standard requirement • "…at a minimum, a West-East orientation should be considered when applying the supplemental event"- the standard requirement does not contain any wording of a minimum consideration • "Geoelectric field outside the local enhancement: a. Amplitude: should not be smaller than 1.2 V/km…" This also does not appear in the standard. • "The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event". This statement creates boundaries outside of requirements, which guidance cannot do. The use of "shall" or "must" should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional "requirement".

Likes 0	
Dislikes 0	
Response	

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 1, 3; Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Louis Guidry

Answer	
Document Name	

Comment
Cleco does agree with the concept, the language, particularly with regard to the extent of the Corrective Action Plan (R11) and various timetable requirements are overreaching and place undue burden on potentially affected entities.

Likes 0	
Dislikes 0	
Response	

Ayman Samaan - Edison International - Southern California Edison Company - 1

Answer	

Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
We don't need to remind the Project 2019-01 SDT that this will be the fourth version of the TPL-007 Reliability Standard in three years. The team has done a fine job of meeting the directives of FERC Order No. 851, but we encourage the SDT to push back harder on the corrective action implementation timeframes for the supplemental GMD event. From a holistic view, this effort to address vulnerability to GMD events appears to be getting too far ahead of good, robust science and engineering. The industry simply does not have mature hardware solutions available to potentially mitigate GIC issues, anticipated from mathematical model simulation software packages that are updating at least as frequently as the TPL-007 standard itself has changed, while constantly chasing the emerging GMD science. The reliability of the BES is, and will be, best served by the improved awareness of GMD impacts embodied by the TPL-007, as well as operator responsiveness required by EOP-010-1. The existing required identification of corrective actions is key; just give industry the time and flexibility to adopt solutions that suit them best.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP thanks the standards drafting team for their efforts on this project.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
The Standard Draft Team (SDT) has added language to submit requests for extensions of timeframes to the ERO, i.e., NERC, for approval. Seminole reasons that individual entities should communicate such requests to the RRO, e.g., SERC, WECC, etc., and that the individual RRO should approve/deny such requests instead of NERC. Seminole is requesting the language be revised to capture this.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	

Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	
Document Name	
Comment	

As previously stated, many of the obligations within TPL-007, both existing and proposed, precede industries' full understanding of GMD and its true, discernable impacts. This proves challenging when attempting to develop standards to adequately address the perceived risks.

We support, and are appreciative of, the efforts of the standards drafting team and their desire to address the directives issued in Order No. 851, however we believe the spirit of those directives can be met without pursuing a path that duplicates obligations already required for the benchmark event. We believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude (one not determined solely by non-spatially averaged data) for a single GMD Vulnerability Assessment (benchmark) that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES. Due to the concerns we have expressed above, AEP has chosen to vote negative on the proposed revisions.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5

Answer	
Document Name	
Comment	

None

Likes 0	

Dislikes 0	
Response	

Consideration of Comments

Project Name: Project 2019-01 Modifications to TPL-007-3
Comment Period Start Date: 7/26/2019
Comment Period End Date: 9/9/2019
Associated Ballots: Project 2019-01 Modifications to TPL-007-3 TPL-007-4 IN 1 ST

There were 66 sets of responses, including comments from approximately 133 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aubrey Short	4		FE VOTER	Ann Carey	FirstEnergy	6	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aubrey Short	FirstEnergy	4	RF
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Bobbi Welch	Midcontinent Independent System Operator	2	MRO
					Mark Holman	PJM Interconnection, L.L.C.	2	RF

					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO

Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrianne Collins	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no NGrid and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC

					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC

					Randy MacDonald	NB Power Corporation	2	NPCC
PSEG	Sean Cavote	1,3,5,6	FRCC,NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Jamison Cawley	Nebraska Public Power District	1	MRO

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with replacing the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis. Since R7.4 is for “situations beyond the control of the entity,” it does not matter if the extensions are considered on a case-by-case basis as the entity will not be able to comply with the CAP timeline as the situation was beyond their control. Adding the case-by-case basis would increase the administrative burden to entities while adding very little benefit to the reliability of the BPS.	
Likes 6	Orlando Utilities Commission, 1, Staley Aaron; Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 851 (P. 54) states that R7.4 (in TPL-007-3) differs from Order No. 830 by allowing applicable entities, under certain conditions, to extend corrective action plan implementation deadlines without prior approval. FERC Order No. 851 (P. 56) directs NERC to modify R7.4 by developing a timely and efficient process, consistent with the Commission’s guidance in Order No. 830, to consider time extension requests on a case-by-case basis. The 'exception' for situations beyond the control of the responsible entity in TPL-007-3 R7.4 is hence replaced by submitting an extension request to the ERO Enterprise on a case-by-case basis as described in the DRAFT TPL-007-4 CAP Extension Request Review Process document.	

Kenya Streeter - Edison International - Southern California Edison Company – 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Russell Noble - Cowlitz County PUD – 3	
Answer	No
Document Name	
Comment	
The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES.	

Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension review process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot. TPL-007-4 is a performance based standard and it does not address the administrative steps of the extension review process. The Electric Reliability Organization (ERO) Enterprise will determine the extension review process (deadlines, appeal process, flow process, status check, etc).	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	No
Document Name	
Comment	
Reclamation recommends Requirement R7 be phrased in terms of a responsible entity's required action, not an action required by a CAP. Reclamation also recommends restructuring TPL-007 so that one requirement in TPL-007 addresses corrective action plans for both benchmark and supplemental GMD Vulnerability Assessments. Reclamation offers the following language for this requirement (see the response to Question 2 regarding the numbering): R10. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 or the Supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met.	

10.1. The responsible entity shall develop the CAP within one year of completion of the benchmark GMD Vulnerability Assessment or Supplemental GMD Vulnerability Assessment.

10.2. The CAP shall contain the following:

10.2.1. A list of System deficiencies and the associated actions needed to achieve required System performance.

10.2.2. A timetable, subject to the following provisions, for implementing each action identified in 7.2.1:

10.2.2.1. Any implementation of non-hardware mitigation must be complete within two years of development of the CAP; and

10.2.2.2. Any implementation of hardware mitigation must be complete within 4 years of development of the CAP.

10.3 The responsible entity shall provide the CAP to the following entities within 90 days of development, revision, or receipt of a written request

10.3.1. Reliability Coordinator;

10.3.2. Adjacent Planning Coordinator(s);

10.3.3. Adjacent Transmission Planner(s);

10.3.4. Functional entities referenced in the CAP; or

10.3.5. Any functional entity that submits a written request and has a reliability-related need for the CAP.

10.4. If a recipient of a CAP provides documented comments about the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

10.5. If a responsible entity determines it will be unable to implement a CAP within the timetable provided in part 7.2.2, the responsible entity shall:

10.5.1. Document the circumstances causing the inability to implement the CAP within the existing timetable;

10.5.2. Document the reason those circumstances prevent the timely implementation of the CAP (including circumstances beyond the entity's control); 10.5.3. Document revisions to the actions identified in part 7.2.1 and the timetable in part 7.2.2; and 10.5.4. Submit a request for extension of the revised CAP to the ERO. Regarding R10.2.2, Reclamation recommends against mandating industry-wide timelines due to the differences in each entity's capabilities to meet deadlines. For example, the differences in procurement processes and timelines among entities. Regarding R10.5, Reclamation recommends the standard describe an extension policy. Regional entities may not be capable of fully researching the entire interconnection in order to provide adequate approvals. Reclamation recommends the regional entities or the ERO automate the CAP tracking process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that the language in R7 and R11 clearly indicates what the entity must do and what shall be in the CAP.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the language in Requirements R7.3 and R7.4 believing the proposed changes meet the intent of Order 851. However, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs additional details to ensure efficient processing of entity CAP Extension Requests, including: 1. A process flow diagram documenting the CAP Extension Process and roles and responsibilities of participants, including the ERO and its authority in this process. 2. NERC contact information where companies can quickly and efficiently check the status of their CAP Extension Requests. 3. Defined deadlines for the completion of CAP Extension Request reviews by NERC and responding to entity inquiries. 4. A process for extending a CAP review deadline for situations where NERC may need additional time. 5. Criteria for a CAP Extension Request 6. An appeals process for denied CAP Extension Requests. 7. A formal process to notify entities on the final ruling for all CAP Extension Requests. 8. Identification of who has oversight of the process within the ERO.	

While EEI recognizes that the SDT is still early in the development phase of the TPL-007-4 Reliability Standard, we believe it is important to emphasize that having a strong CAP Extension Request process is crucial to ensuring that the directed CAPs are effectively and efficiently processed, similar to the BES Exceptions Process (see Rules of Procedure, Appendix 5C; Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Chris Scanlon - Exelon – 1	
Answer	No
Document Name	
Comment	
Exelon agrees with EEI's comments. Exelon believes that the SDT has proposed changes to Requirements R7.3 and R7.4 that meet the intent of the FERC directive in Order 851 but feel it requires further modifications. The Draft TPL-007-4 CAP Extension Request Review Process does not provide the requesting entity with a clear understanding of how the request will be considered, when a decision can be expected, and how an entity could request reconsideration if an extension is denied. With the FERC directive requiring ERO involvement in this case, this justifies placing an obligation on the ERO. The development of a well-defined process similar to the Technical Feasbility Exception Process or the BES Exceptions Process should be concurrently developed and submitted along with the proposed standard to facilitate NERC's engagement. This will provide a mechanism to address the key items noted in EEI's comments. On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 1 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No

Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
This requirement gives responsibility to an entity which is not an applicable entity under the Standard. The requirement as written also has no impact on reliability, it is purely an administrative requirement and does not directly provide the entitiy with an approved extension. There should be a requirement added which requires the entity that receives the request for CAP extension approve the request within a specified timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a	

Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the modifications to R7.4 meet the directive in FERC Order. No. 851 by replacing the corrective action plan time-extension provisions in R7.4 with a process that extensions of time are considered on a case-by case basis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirement R7, Part 7.4 meets the directive of FERC Order No. 851, Paragraph 54. The FERC directive is extremely narrow and the Project 2019-01 SDT has met the intent to require a process to consider time extensions on a case-by-case basis. However, the FERC directive did not demand that the ERO be the adjudicating entity for time extensions and we suggest the following revision to each ERO reference in the proposed TPL-007-4: "ERO, or its delegated designee." We believe that this modification will allow Regional Entities or other designees to better adjudicate CAP time extensions given their closer proximity, System expertise, and existing Compliance Program obligations.	
Likes 1	Orlando Utilities Commission, 1, Staley Aaron

Dislikes 0	
Response	
Thank you for your comment. The language in R7.4 and R11.4 has been modified to clarify intent.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Do you agree that R7 meets the directive? my possible answer is NO. **Please see EEI's comments**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
The proposed language meets the FERC directive.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA understands that the SDT had to respond with proposed changes to meet the directive for R7. BPA does not agree that entities should have to request approval from the ERO for an extension to the Corrective Action Plan for circumstances that occur beyond the entities control. BPA would like to utilize the new ERO Portal tool to allow NERC and the Commission immediate access in real time to the corrective action plan extensions and the justification for the extension. Retaining the requirement as written gives entities the flexibility to respond to unanticipated circumstances without the administrative burden of seeking an extension from NERC. NERC and the Commission would be able to determine if entities are abusing this flexibility and if abuse occurs, should seek to remedy at that time.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

Thank you for your comment. FERC Order No. 851 (P. 54) states that R7.4 (in TPL-007-3) differs from Order No. 830 by allowing applicable entities, under certain conditions, to extend corrective action plan implementation deadlines without prior approval. FERC Order No. 851 (P. 56) directs NERC to modify R7.4 by developing a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-by-case basis. The 'exception' for situations beyond the control of the responsible entity in TPL-007-3 R7.4 is hence replaced by submitting an extension request to the ERO Enterprise on a case-by-case basis as described in the DRAFT TPL-007-4 CAP Extension Request Review Process document. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff.

Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
I agree that the language meets the directive, but would it make more sense for the standard to assign this to the regional entities instead of the ERO?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.4 and R11.4 has been modified to clarify intent.	

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Agree that R7 meets the directive. Do not agree that Part 7.4 should require the request for extension be submitted to the ERO for approval. It makes more sense the request be submitted to the Regional Entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.4 and R11.4 has been modified to clarify intent.	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Eversource agrees with the modification of Requirement R7.4 to meet the directive of Order No. 851. However, Eversource does note that the proposed R7 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff.	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes

Document Name	Project 2019-01 Comment Form Attachment.docx
Comment	

ISO/RTO Council Standards Review Committee members ERCOT, MISO, NYISO, PJM, and SPP (the "SRC") submit the following comments regarding Project 2019-01 Modifications to TPL-007-3.

The SRC agrees that the revisions to Requirement R7 proposed by the SDT satisfy FERC's directive in Order 851 regarding extensions of time to implement corrective action plans on a case-by-case basis. In order to further streamline Requirement R7 and more closely align Requirement R7 to the specific language in FERC's directive, the SRC offers the proposed revisions described below and identified in the attached for consideration by the SDT.

In connection with Part 7.3, mentioning the ERO approval processes is not necessary given that Part 7.4 addresses the process. Deleting the reference ("ERO approval for any extension sought under") would result in a more streamlined requirement, and would more closely align with FERC's directive that *Part 7.4* be modified to incorporate the development of a timely and effective extension of time review process. This proposed revision to the current draft of Part 7.3 proposed by the SDT is identified in the attached redline.

In connection with Part 7.4, the SRC suggests the SDT consider:

1. Including express language that an extension of time is "subject to the approval of NERC and the reliability entity's Regional Entity(s) on a case-by-case basis" in order to more closely align Part 7.4 with FERC's specific directive that Part 7.4 be modified and that requests for extension of time are to be reviewed on a "case-by-case basis."
2. Utilizing "NERC and the reliability entity's Regional Entity(s)" instead of "ERO" in order to more closely align with the specific language utilized in Order 851.

3. Including “of time” in order to more clearly articulate what type of extension is available under Part 7.4 These proposed revisions to the current draft of Part 7.4 proposed by the SDT are identified in the attached redline.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	

Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates the standard drafting team's (SDT) efforts to meet the FERC directives. Texas RE has a few concerns as to how the SDT approached the directives. First, Texas RE is concerned with the following language in Part 7.4: Additionally, Texas RE is concerned with the ERO's role involving the process for granting CAP extensions. Texas RE asserts that it may be more appropriate to keep operational aspects of the BPS within the hands of the owners/operators and simply make the ERO aware of the CAP. For example, Texas RE suggests that the RC is the appropriate entity to accept/approve the extensions for CAPs. In addition, there could also be a requirement for the registered entity to inform its CEA of a CAP extension. This way, the ERO can verify compliance as far as the RC reviewing extensions of the CAPs and the ERO would not become part of the compliance evaluation and processes of the	

standard by not having to verify that they themselves reviewed the CAP extension. Moreover, this is consistent with Reliability Standard PRC-012-2 Requirement R6, which requires the RAS-entity submit the CAP to its reviewing RC as the RC has the relevant expertise to review the CAP. • Part 7.4.1 requires entities to document how circumstances causing delay are beyond the control of the responsible entity, but Part 7.4 does not include language to specify that an extensions are only allowed when "situations beyond the control of the responsible entity [arise]." (FERC Order No. 851). Texas RE recommends updating Part 7.4 to include requirements for extension so implementation issues do not get categorized as documentation issues under Part 7.4.1. • Part 7.4 only specifies that CAP extensions shall be submitted but does not include language requiring that CAP extensions be approved. While the Draft TPL-007-4 CAP Extension Request Review Process, which is outside of the requirement language, sates "All CAP extension requests must be approved the ERO Enterprise prior to the original CAP completion date", it may be helpful to specify the timetables for extension requests in relation to the timetables for implementation in the original CAP to avoid scenarios in which the responsible entity submits an extension request immediately prior to the planned implementation date. • Neither the requirement nor the Draft TPL-007-4 CAP Extension Request Review Process indicate what shall occur if a CAP extension request is not approved. •	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document expresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs) developed under TPL-007-4. The DRAFT TPL-007-4 CAP Extension Request Review Process document was developed by NERC Compliance Assurance, not Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE

Answer	No
Document Name	

Comment

Comment is the same as question #1.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 2 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

Exelon agrees with EEI's comments and believes that the same concerns expressed in the response to Question 1 are applicable to R11 as well.

On Behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

TVA supports comments submitted by AEP for Question #2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers. FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……” The SDT has elaborated on the supplement event to the Implementation Guidance document.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the language in Requirements R11 believing the proposed changes meet the intent of Order 851. However as stated in more detail in our response to Question 1, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs to include additional details to ensure effective and transparent processing of entity CAP Extension Requests.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends combining the TPL-007 CAP requirements in R7 and R11 as provided above in response to Question 1. If Reclamation's proposal is accepted, Reclamation recommends restructuring and renumbering the requirements in TPL-007 as follows: R1 through R6 – no change R7 – remove and combine CAP language with existing R11 R8 – renumber existing R8 to R7 R9 – renumber existing R9 to R8 R10 – renumber existing R10 to R9 R11 – combine CAP language from existing R7; renumber the new single CAP requirement to R10 R12 – renumber existing R12 to R11 R13 – renumber existing R13 to R12	

This will improve the logical flow of the activities required by the revised standard. Reclamation also recommends the SDT add a heading between the new M9 and R10 for "Corrective Action Plans" for consistency with the existing headings "Benchmark GMD Vulnerability Assessments" between M3 and R4, "Supplemental GMD Vulnerability Assessments" between M7 and R8, and "GMD Measurement Data Processes" between M11 and R12.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
ACES believes that the directive could have been dealt with in a less onerous way that addresses concerns other entities have expressed, in their comments, about the potential for duplication of effort between the baseline corrective action plans and supplement corrective action plans. To alleviate some of that potential, the standard could expressly state that corrective action plans are only required for supplemental GMD Vulnerability Assessments, if the corrective actions plans identified for the baseline GMD Assessments do not already address any additional vulnerabilities identified by the supplemental GMD Assessments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT does not believe there is a duplication of efforts. A single corrective action plan could address both the benchmark and supplemental vulnerability assessment, or the entity could develop separate corrective action plans for the benchmark event or the supplemental event.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Comments: NIPSCO does not agree with the Requirement R11 that requires development and implementation of Corrective Action Plan (CAP) for Supplemental GMD events. Judging by the reference geoelectric field values to be utilized for the Supplemental event, the effort appears to be duplicative of the benchmark GMD event (8V/km) with a higher magnitude of 12V/km. As such, we believe the supplemental event represents an “extreme” version of a case that will be assessed under the defined benchmark event. As corrective action plans are to be developed and implemented for the benchmark GMD event(Requirement R7), requiring CAP for Supplemental event will unnecessarily burden companies for cases that represents an extreme system condition and is not the best cost effective approach to meet the FERC directive	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. However, FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”	
Russell Noble - Cowlitz County PUD - 3	
Answer	No

Document Name	
Comment	
See question one.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension review process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot. TPL-007-4 is a performance based standard and it does not address the administrative steps of the extension review process. The Electric Reliability Organization (ERO) Enterprise will determine the extension review process (deadlines, appeal process, flow process, status check, etc).	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension	

process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with requiring the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Entities have only just begun the process of evaluating the benchmark GMD event and developing mitigation measures. The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Thank you for your comment. However, FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”	
Thomas Foltz - AEP - 5	
Answer	No

Document Name	
Comment	

While some aspects of R11 may indeed meet the directives as ***literally*** stated in Order No. 851, we do not believe it is a prudent way to meet the ***spirit*** of those directives. We believe R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and disagree with its inclusion. In addition, the obligation to "specify implementation" of mitigation may not be consistently interpreted among entities, and as a result, may not meet the directives for reasons we will provide in this response.

It is our view that the original purpose of the supplemental event was to investigate the impact of local enhancement of the generated electric field from a GMD event on the transmission grid. This requires industry to take an approach in which the GICs are calculated with the higher, enhanced electric field magnitude of 12 V/km (adjusted for location and ground properties) applied to some smaller defined area while outside of this area the benchmark electric field magnitude of 8 V/km (also adjusted for location and ground properties) is applied. This smaller area is then systematically moved across the system and the calculations are repeated. This is necessary as the phenomenon could occur anywhere on the system. Using this Version 2 methodology, every part of the system is ultimately evaluated with the higher electric field magnitude.

In our view, the supplemental event represents a more extreme scenario. Referring to Attachment 1 of the proposed standard, the section titled '**Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event**' provides examples of applying the localized peak geoelectric field over the planning area. The first example presented is applying the peak geoelectric field (12 V/km scaled to planning area) over the entire planning area. This example is a more severe condition than the benchmark event, and should alleviate the need to study the benchmark event if used. In addition, modeling tools for conducting GMD vulnerability studies for the supplemental event using the moving box method have not yet been developed. As such, adding a corrective action plan requirement to the supplemental event obviates the need for studying the benchmark event. Rather than pursuing a Corrective Action Plan for the existing Supplemental GMD Vulnerability Assessment, we believe the SDT should instead pursue only one single GMD Vulnerability Assessment using a reference peak geoelectric field amplitude not determined solely by non-spatially averaged data. This would be preferable to requiring two GMD Vulnerability Assessments, both having Corrective Action Plans and each having their own unique reference peak geoelectric field amplitude. When the Supplemental GMD Vulnerability Assessment was originally developed and proposed, there was no CAP envisioned for it. Because of this, one could argue the merits of having two unique assessments, as each were different not only in reference peak amplitude, but in obligations as well. What has now been proposed in this revision however, is essentially having two GMD Vulnerability Assessments requiring Corrective Action Plans but with different reference peak geoelectric field amplitudes (one presumably higher than the other). It would be unnecessarily burdensome, as well as illogical, to have essentially the same obligations for both a baseline and supplemental vulnerability assessment. In addition to its duplicative nature, it is possible that the results from a benchmark study may even differ or conflict with the results from a given supplemental study.

While the NOPR directs the standard to be revised to incorporate the "development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities", we find rather that R11 requires the entity "specify implementation" of mitigation. This could be interpreted by some as simply specifying what actions are to be taken but without explicit bounds or expectations on when the final execution of that implementation (i.e. "completion") would take place.

Once again, we believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude for a single GMD Vulnerability Assessment (benchmark), one not determined solely by non-spatially averaged data, and that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES.

Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	

Response

Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers.

FERC order 851 requires the SDT to develop a CAP for supplemental event:

"The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……"

The SDT has elaborated on the supplement event to the Implementation Guidance document.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	
The SRC agrees that adding Requirement R11, which is based on the existing language of Requirement R7, satisfies FERC's directive in Order 851 regarding the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. To the extent the SDT incorporates in Requirement R7 the SRC's suggested revisions identified in response to Question No. 1 above, the SRC proposes the SDT make the same revisions to Requirement R11.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the addition of Requirement R11 to meet the directive of Order No. 851. However, Eversource does note that the proposed R11 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The SDT has met the directive in Order 851. BPA understands that the SDT had to respond with proposed changes to meet the directive for R11. BPA would like to reiterate the industry's and NERC's opposition to developing corrective action plans for an extreme event (Supplemental GMD event) and the similarity to TPL-001-4. A GMD event is considered to be a one in one hundred year event. BPA believes that assessing the event and performing	

an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan.

BPA supports the comments made by NERC, referenced in FERC's Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC's comments reiterate the rationale in its petition that requiring mitigation

"would result in the de facto replacement of the benchmark GMD event with the

proposed supplemental GMD event." **39** NERC maintains that "while the supplemental

GMD event is strongly supported by data and analysis in ways that mirror the benchmark

GMD event, there are aspects of it that are less definitive than the benchmark GMD event

and less appropriate as the basis of requiring Corrective Action Plans."**40** NERC also

claims that the uncertainty of geographic size of the supplemental GMD event could not

be addressed adequately by sensitivity analysis or through other methods because there

are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation

grounding grid resistance values, transformer thermal and magnetic response models) …

[and] introducing additional variables for sensitivity analysis, such as the size of the

localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."**41**

39 *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most

conservative approach for conducting supplemental GMD Vulnerability Assessments,

which would be to apply extreme peak values uniformly over an entire planning area”). **40** *Id.* at 13. **41** *Id.* at 15.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Thank you for your comment. FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
The proposed language meets the FERC directive.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Do you agree that R11 meets the directive? my possible answer is NO. **Please see EEI's comments**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirement R11 meets the directive of FERC Order No. 851, Paragraph 39. Again, the FERC directive leaves little room for flexibility, requiring CAPs for the supplemental GMD event. While we are disappointed that FERC was not persuaded by the technical challenges of simulating locally-enhanced peak geoelectric field suitable for supplemental GMD event analysis, the Project 2019-01 SDT has met the intent.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R11 meets the requirements in FERC Order 851. The modifications to R11 properly address Order 851's requirement to develop CAP to mitigate assessed supplemental GMD event vulnerabilities with provisions for extension of time on a case-by-case analysis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE's comments regarding Part 7.4 in question #1 as they also apply to Part 11.4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document expresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs) developed under TPL-007-4. The DRAFT TPL-007-4 CAP Extension Request Review Process document was developed by NERC Compliance Assurance, not Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. The language in R7.3, R7.3, R11.3, and R11.4 has been modified to clarify intent.	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
PSE will abstain from answering this question	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
N/A	
Likes 1	Western Area Power Administration, 6, Jones Rosemary
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The Canadian variance does not completely reflect the unique regulatory process in each region in Canada. The Manitoba Hydro Act prevents adoption of reliability standards that have the effect of requiring construction or enhancement of facilities in Manitoba. Manitoba Hydro modified the language of TPL-007-2 that works in Manitoba.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The SDT acknowledges the jurisdictional issues mentioned. It is noted that jurisdictional regulations may have limits on standard adoption, and entities may have standard making authority.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
No comments were submitted by EEI for Question 3.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the Canadian variance portion of the standard is helpful for the utilities in the United States. However, SCL cannot comment on the language of the standard in the Canadian Variance portion where it relates to regulatory process in Canada.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP is not impacted by the Canadian variance..	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
No comments were submitted by EEI for Question 3.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
For the parts of the proposed changes to R7 (new R10) stated in the response to Question 1 that are accepted, Reclamation recommends conforming changes be made to the pertinent language in the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. There are no equivalent changes to the Canadian Variance based on the comments and changes made to the standard from Reclamations Question 1 response.	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	

Comment	
Eversource has no opinion on the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
The IRC SRC did not provide any comments for Question 3.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	

The Canadian member of the SRC agrees that the Canadian variance is written in a way that accommodates the regulatory process in Canada.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	
Document Name	
Comment	
Not applicable to FirstEnergy.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
CHPD defers the response to this question to the Canadian provinces to determine if the Canadian variance is written to accommodate the regulatory processes in Canada.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
GTC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
PSE will abstain from answering this question	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	

Answer	
Document Name	
Comment	
GSOC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
EEI did not provide a response to Question 3.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	

Likes 0	
Dislikes 0	
Response	
EEI did not provide a response to Question 3.	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
IPl is not in the Canadian district	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 4 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
As discussed in the response to Question 1, Exelon agrees that changes in Requirements R7, R8 and R11 meet the intent of the FERC directives, but without a clear CAP Extension Process the changes cannot be supported at this time. On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension	

process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
See response to Q2 above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers. FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……” The SDT has elaborated on the supplement event to the Implementation Guidance document.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports the language in Requirements R7, R8 and R11 as proposed by the SDT believing that the changes conform to the directives contained in Order 851. Nevertheless, we cannot support these changes as sufficient or complete at this time until a CAP Extension Request Review Process is develop that ensure that key elements, as articulated in our response to Question 1, are addressed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	

Answer	No
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends the language in Requirements R7 and R11 be combined into a single requirement addressing corrective action plans. Please refer to the proposed language provided in the responses to Questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and	

avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with the directives in FERC Order No. 851 for “Corrective Action Plan Deadline Extensions” or “Corrective Action Plan for Supplemental GMD Event Vulnerabilities” (see responses to questions 1 and 2). Therefore, CHPD does not agree the standard language changes in Requirement R7, R8, and R11 proposed by the SDT.	

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Thank you for your comment. The SDT believes we have met the directives of the FERC order.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	Yes
Document Name	

Comment

The SRC agrees that the revisions to Requirements R7, R8, and R11 substantially satisfy FERC's directives articulated in Order No. 851, and refers the SDT to the comments provided in response to Question Nos. 1 and 2.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.

Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF

Answer	Yes
Document Name	

Comment

MISO supports the comments submitted by the IRC SRC.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The SDT has met the directive in Order 851.

BPA understands that the SDT had to respond with proposed changes to meet the directive. BPA believes requiring a corrective action plan for a Supplemental GMD Event is unreasonable and imposes an unnecessary burden on transmission owners and operators.

BPA believes that mitigation strategies for GMD events and the ensuing geomagnetically induced currents would likely be considered novel and in the Research and Development or prototype stages. As such, most devices or control/relay schemes that might be part of a corrective action plan could increase operational complexity and a potential loss of system security. While attempting to mitigate the risk from a low frequency benchmark GMD event, additional risk may be introduced which results in a net reduction in system security. Hence, there is caution from utilities and the industry in general about mandating corrective action plans for schemes and devices that are not well developed and commonly deployed.

BPA supports the comments made by NERC, referenced in FERC’s Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC’s comments reiterate the rationale in its petition that requiring mitigation

“would result in the de facto replacement of the benchmark GMD event with the

proposed supplemental GMD event.” **39** NERC maintains that “while the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis of requiring Corrective Action Plans.”**40** NERC also claims that the uncertainty of geographic size of the supplemental GMD event could not be addressed adequately by sensitivity analysis or through other methods because there are “inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) … [and] introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments.”**41** **39** *Id.* at 11-12; *see also id.* at 14 (“many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area”). **40** *Id.* at 13. **41** *Id.* at 15.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response	
Thank you for your comment. FERC order 851 requires the SDT to develop a CAP for supplemental event: "The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……"	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
The proposed language meets the FERC directive.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
my possible answer is NO. **Please see EEI's comments**	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirements R7, R8, and R11 meets the directives of FERC Order No. 851. However, FERC has not mandated the specific timetable proposed in Requirement R11, Part 11.3. Considering the 150% geoelectric field enhancement reflected by the supplemental GMD event over the benchmark GMD event, we suggest that the Project 2019-01 SDT modify Requirement R11, Parts 11.3.1 and 11.3.2 to three and six years, respectively.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes consistent timelines is the best practice for implementing TPL-007-4, non-hardware mitigations shall be completed within two years and hardware mitigations shall be completed within four years. In addition, the extension process will allow entities that encounter situations beyond their control to request extensions of time.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R7, R8, and R11 properly address the requirements in FERC Order 851 as noted under 1 and 2 above.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE's answer to #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document expresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs)	

developed under TPL-007-4. The DRAFT TPL-007-4 CAP Extension Request Review Process document was developed by NERC Compliance Assurance, not Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	No
Document Name	
Comment	
No comments on the modified VRF/VSL for Requirements R7, R8 and R11	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	

Answer	No
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 5.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 5.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

No comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 5.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	No
Document Name	
Comment	

None.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees with the descriptions of VRF/VSL in the standard for requirements R7, R8, and R11.	
Likes 0	
Dislikes 0	
Response	
The SDT thanks you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

Reclamation recommends combining R7 and R11. For consistency, Reclamation also recommends the VRF/VSL for these requirements be combined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 5.	

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Continuing with a previous standard's implementation plan causes confusion, misunderstandings, and the increased potential for missed deadlines. Reclamation recommends retiring the implementation plans for previous versions of TPL-007 and creating a new implementation plan for TPL-007-4 so there is only one implementation plan to work toward.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Although there are some additions to the requirements, the implementation plan for TPL-007-4 (the revised standard) is the same as the existing, approved TPL-007-3 standard with the exception of R11, which is a new requirement in TPL-007-4. Despite the additions, the SDT believes this implementation plan allows sufficient time for applicable entities to meet the added requirements in the revised standard.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 6.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The implementation plan is likely long enough but does it make sense to have a standard in place that won't be effective for several years? Based on Canadian Law, when a standard is adopted it becomes immediately effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The implementation plan establishes future compliance dates which allows the applicable entities, as established in R1, sufficient time to prepare to meet the requirements. The implementation plan also provides that a governmental authority may provide different dates.	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	

CHPD does not agree with requiring a CAP for supplemental GMD event (TPL-007-4 R11). Therefore, CHPD does not agree with the implementation plan which requires compliance with R11.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Thank you for your comment. Requirement R11 was added by the SDT to address the FERC directive in Order No. 851 (Paragraphs 4 and 39 of the Order) which requires CAPs for the vulnerabilities identified in the supplemental GMD analysis.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	

None.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments for Question 6.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comment	

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments for Question 6.	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Implementation Plan is consistent; essentially no TPL-007-3 Compliance Dates are changed, except for the modified Requirements R7 and R11 (Requirement R8 proposed changes are trivial). Given the expectation of a rapid FERC approval process, the 01 January 2024 Compliance Dates to develop corrective actions for the supplemental GMD event are reasonable.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees with the impmentation plan for R7, R8, and R11. However, SCL would like to see a later effective date for R12 and R13 or clear guidelines on how to monitor and collect GIC from at least one GIC monitor located in the Planning Coordinator's area.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did not change the effective dates for R12 and R13 (R11 and R12 in TPL-007-3) from those in the previous version of the standard. The applicable entity for this requirement is determined in R1. The R12 requirement states "in the Planning Coordinators area or in the Planning Coordinator's GIC System model." The SDT drafted a Technical Rationale document where more information can be found.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that TPL-007-3 is incorrectly referenced on page 1 of the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that TPL-007-3 is correctly referenced in the Implementation Plan.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	

Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 6.	

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

TPL-007-4, in contrast to the majority of standards established by NERC, GMD Vulnerability Assessments are not representative of an existing utility practice. This is highlighted by the fact that there is a deficit of modeling tools available that would enable an entity to comply with the requirements specified herein. The burden of expenses relative to CAPs has yet to be established because there are very few examples of vulnerability assessments that have been completed for either the benchmark or the supplemental GMD events. In essence, the science to prudently study and assess system vulnerabilities related to a High Impact, Low Frequency (HILF) event on the system is not conclusive and still subjective. In short, the obligations have come before the development of proven modeling tools and mitigation techniques. Once again, AEP believes that R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and as such, we do not believe it to be cost effective. Those resources would be better served for efforts having a discernable, positive impact on the reliability of the BES. Rather than pursuing this course, we believe a more prudent path, as well as a more cost effective path, would be as we propose in our response to Q1.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers.

FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
No, we do not agree that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner; the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are too short thereby escalating costs. We echo industry comments made during previous modifications to TPL-007-1: FERC opened the door for NERC to propose alternatives to the two- and four-year implementation of corrective actions (FERC Order No. 830, Paragraph 97); FERC was clearly persuaded by device manufacturers over the concerns of utility commenters that mitigation deadlines were impractical (FERC Order No. 830, Paragraph 102). This was particularly problematic because the hardware solutions that existed then, as well as today, remain widely unproven (only one implementation in the continental United States) and are simply not suitable for highly networked Systems (blocking GICs pushes the problem onto neighbors). Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT believes having the same CAP timelines for both the benchmark and supplemental GMD vulnerability assessments is consistent with FERC Orders 830 and 851. In addition, the extension process will allow entities that encounter situations beyond their control to request extensions of time. Examples of situations beyond the control of the entity for which extensions of time may be approved are contained in the Implementation Guidance document. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Reliability Coordinator (RC), not the ERO. The RC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek RC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the RC for approval. This is a more appropriate and cost-effective approach to addressing the requests.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate".	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No

Document Name	
Comment	

The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

FERC order 851 requires the SDT to develop a CAP for supplemental event:

"The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……"

Bruce Reimer - Manitoba Hydro - 1

Answer	No
Document Name	
Comment	

The proposed changes mandates implementation of a Corrective Action Plan for the supplemental GMD event (12 V/km). The research into this type of disturbance is still evolving. The available tools do not support studying this disturbance at this time. The tools available would allow for a uniform field over the entire planning Coordinator area. If this field is increased from 8 V/km to 12 V/km that corresponds to a

disturbance well in excess of the 1/100 year level suggested by the benchmark. This is not just and reasonable. Let TPL-007-2 run through its first cycle of studies and review the assessment results. Perhaps the next cycle of studies could evolve to the proposed wording in TPL-007-4 once the research and tools have matured and an assessment of the potential costs have been tabulated to address the supplemental event.	
Likes 0	
Dislikes 0	
Response	
FERC order 851 requires the SDT to develop a CAP for supplemental event: “The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments for Question 7.	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	No

Document Name	
Comment	
It is difficult to assess the exact financial impacts of the requirements in this standard. The addition of CAP for Supplementary GMD event may or may not be cost effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees that the SDT satisfied its obligation to modify TPL-007 to meet the directives in FERC Order No. 851. BPA can not determine if the directives are cost effective. The modifications are requiring a corrective action plan for an extreme event (Supplemental GMD event). The Transmission Planners and Transmission Owners have not done the analysis to determine the impact and the cost of the corrective action plans that would be required. BPA believes without this analysis, the cost effectiveness can not be determined. BPA believes that assessing the event and performing an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam

Dislikes 0	
Response	
Thank you for your comment.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
We are concerned the cost and effort to address this standard could hinder other more important Transmission improvements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Comments: See comments on Question 2	
Likes 0	
Dislikes 0	
Response	
Thank you for your response, please see answer on Question 2.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
If unintended duplication of efforts between baseline and supplemental corrective action plans occurs, as referenced in the response to question 2, that would lead to unnecessary increases in costs to registered entities. Please reference the suggestion in our response to question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT does not believe there is a duplication of efforts. A single corrective action plan could address both the benchmark and supplemental vulnerability assessment, or the entity could develop separate corrective action plans for the benchmark event or the supplemental event.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
For the implementation of numerous, overlapping versions of the same standard (such as the implementation of TPL-007-2, TPL-007-3, and TPL-007-4) with lengthy phased-in implementation timelines, Reclamation supports the incorporation of insignificant subsequent modifications (such as the changes from TPL-007-2 to TPL-007-3 to TPL-007-4) in accordance with existing phased-in implementation milestones, but recommends that all previous implementation plans be retired so that there is only one implementation plan in effect at a time.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Although there are some additions to the requirements, the implementation plan for TPL-007-4 (the revised standard) is the same as the existing, approved TPL-007-3 standard with the exception of R11, which is a new requirement in TPL-007-4. Despite the additions, the SDT believes this implementation plan allows sufficient time for applicable entities to meet the added requirements in the revised standard.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) has no concerns to cost effective issues from a Planning Coordinator (PC) perspective, however, from the SPP membership perspective, the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are short, thereby escalating costs over two and four years. This timeframe could create issues for hardware solutions. Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Examples of situations beyond the control of the entity for which extensions of time may be approved are contained in the Implementation Guidance document. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

TVA supports comments submitted by AEP for Question #7

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers.

FERC order 851 requires the SDT to develop a CAP for supplemental event:

“The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……”

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO

Answer	No
Document Name	

Comment

Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Planning Coordinator (PC), not the ERO. The PC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek PC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the PC for approval. This is a more appropriate and cost-effective approach to addressing the requests.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The language in R7.4 and R11.4 has been modified to clarify intent.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The language in R7.4 and R11.4 has been modified to clarify intent.	

Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees; however, it is difficult to assess the true financial impacts of the requirements in this standard to SCL at this early stage. The modifications in the standard may or may not be cost-effective to SCL.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 7.	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
NERC should evaluate the relative event probabilities with respect to the cost/benefit analysis of GMD event mitigations. Planning for increasingly rare system events is inherently at odds with economic planning and rate payer responsibilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
More experience with implementing the standard is required in order to better understand the implications on its cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	

Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 7.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	

Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. EEI did not provide comments on Question 7.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

8. Provide any additional comments for the standard drafting team to consider, if desired.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	
Document Name	
Comment	
Nothing further	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bette White - AES - Indianapolis Power and Light Co. - 3	

Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	
Document Name	
Comment	
In Requirements R7 and R11, the SRC suggests replacing “their” with “its” just prior to the first mention of “System” for grammatical reasons.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT implemented the suggested editorial change to R7 and R11.	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	

Document Name	
Comment	

MISO supports the comments submitted by the IRC SRC. In addition, MISO would like to propose a clarification to requirement R6, part 6.4.

As written, the Transmission Owner and Generator Owner functions referenced under TPL-007-4, requirement R6, Part 6.4 are not functions that are included in the identification of the individual and joint responsibilities under TPL-007-4, requirement R1. As a result, when the Planning Coordinator, in conjunction with its Transmission Planner(s) identifies the individual and joint responsibilities, the Transmission Owner and Generator Owner are not party to this information and so would not know who to provide the results to.

In addition, there is no provision under R1 that requires the Planning Coordinator to determine or communicate who applicable Transmission Owners (section 4.1.3) and Generator Owners (section 4.1.4) within its area should send the results of their benchmark thermal impact assessment to.

MISO became aware of this gap following an inquiry from a transformer owner when they did not know where to send the results.

Possible remedies:

1) Modify Requirement R6, Part 6.4 to reference Requirement 5, i.e. “Be performed and provided to the responsible entity(ies) ***that provided the GIC flow information in accordance with Requirement 5***, within 24…

2) Clarify the scope of requirement Require R1 to specify that the Planning Coordinator in conjunction with its Transmission Planner(s) determine which responsible entity(ies) applicable Transmission Owner(s) and Generator Owner(s) in their area should send the results of their benchmark thermal impact assessment(s) to.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that this modification is outside the scope of the SAR.	
David Jendras - Ameren - Ameren Services - 3	

Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	
Document Name	
Comment	
The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don't use CMEP Implementation Guidance to establish requirements which go beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following: • "The local geoelectric field enhancement should not be smaller than 100 km.."- this threshold value of 100 km does not appear in the standard requirement	

• “…at a minimum, a West-East orientation should be considered when applying the supplemental event”- the standard requirement does not contain any wording of a minimum consideration • “Geoelectric field outside the local enhancement: a. Amplitude: should not be smaller than 1.2 V/km…” This also does not appear in the standard. • “The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event”. This statement creates boundaries outside of requirements, which guidance cannot do The use of “shall” or “must” should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional “requirement”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT updated the Implementation Guidance document to incorporate this feedback.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	
Document Name	

Comment	
Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 8 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that TPL-007-4 be consistent with other standards that require data to be submitted from the applicable entities to the Regional Entity. Reliability Standards FAC-003-4, EOP-008-2 Requirement R8, and PRC-002-2 Requirement R12 explicitly state the data shall be submitted to the Regional Entity in the requirement language or in Part C. Compliance section of the standard. There is no need for an extraneous process document describing where to submit the information. Texas RE is concerned with introducing a separate process document for submitting CAP extension requests for the following reasons: the document would not be FERC approved, how would entities and regions know that it exists, where would it be housed, etc. Registered entities should not have to look beyond the standard in order to understand how to comply with a requirement.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate". The DRAFT TPL-007-4 CAP Extension Request Review Process document expresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs) developed under TPL-007-4. The DRAFT TPL-007-4 CAP Extension Request Review Process document was developed by NERC Compliance Assurance, not Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. The language in R7.3, R7.4, R11.3, and R11.4 has been modified to clarify intent.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

• R7.1 (page 6 of TPL-007-4 clean draft):
  o The portion of this sub-requirement starting from “Examples include:” should be moved to the Implementation Guidance, as the bullet point list’s purpose is more in line with the stated purpose of the Guidance. Consider updating R11.1 as well.
  o To this end, Page iii of Implementation Guidance Document needs to be updated to reflect new SERC region.
• Consider deleting the four references to Attachment 1 in the Draft Technical Rationale document (Draft Tech Rationale_TPL-007-4.pdf).	

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT believes that maintaining the examples in Requirements R7.1 and R11.1 is reasonable and minimizes confusion. The Electric Reliability Organization (ERO) Enterprise map and corresponding table have been updated in the Implementation Guidance Document. References to Attachment 1 in the Technical Rationale document have been updated for clarity.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
Entergy supports comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI acknowledges and supports the good work by the SDT in support of this Reliability Standard believing that it conforms to the directives issued in FERC Order 851. We also recognize that the supporting/companion ERO process document simply represents an initial draft of the Extension Request Process. Nevertheless, the process of CAP extention reviews and approvals are inextricably tied to the modification of this standard. For this reason and as stated in more detail in our response to Question 1, this companion process document needs to	

include additional details to ensure effective and transparent processing of entity CAP Extension Requests. The process should also be formally codified in parallel with the required revisions to this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	
Document Name	
Comment	

PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	
Document Name	
Comment	
With the change that the Benchmark and Supplimental analysis both require a CAP, shouldn't they be consolidated into a single study effort to reduce the overall number of requirements? The Supplimental seems to only be a Benchmark with additional areas of increased field strength, unless I am missing some nuiance in how they are performed?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers. FERC order 851 requires the SDT to develop a CAP for supplemental event:	

“The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……” The SDT has elaborated on the supplement event to the Implementation Guidance document.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DRAFT TPL-007-4 CAP Extension Request Review Process document is being developed by NERC Compliance Assurance, not by the Project 2019-01 Standard Drafting Team. Your comment on recommended changes to the extension process will be forwarded to NERC Compliance Assurance staff. Note that the extension review process itself is not part of TPL-007-4, and therefore, it is not part of the ballot.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	

Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	
Document Name	
Comment	
What was the rationale behind removing the Supplemental Material? It provided some background information and sources that could be useful for understanding the practicality of the requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. All supporting background information is available at the project page. Additional background material is provided in the Technical Rationale and Implementation Guidance documents (see references to white papers).	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
Comments: 1. The language in Requirement 7.4 doesn't properly align with the FERC Directive on who should be approving the extensions. The FERC directive doesn't clearly state that the ERO should be the entity approving the extension. We recommend the drafting team	

consider revising their proposed language to include “ERO, or its delegated designee.” This modification will allow regional entities or other designees to better adjudicate CAP time extensions given their close proximity, System expertise, and existing compliance program obligations.

2. The proposed language in Requirement R11 Part 11.3 doesn’t align with the FERC directive in reference to the duration of the Implementation of the CAP. The FERC directive doesn’t clarify a specific time frame pertaining to the Implementation of the CAPs. Recommend the drafting team consider revising their proposed language for Requirement R11.3 Parts 11.3.1 and 11.3.2 to include an implementation timeframe of three (3) and six (6) years respectively.

3. The SSRG recommends that the drafting team considers including more technical language in the Technical Rationale document, explaining how/why the drafting team came to their conclusions to revising these particular requirements. The document doesn’t provide technical reasoning the drafting team developed or revised this requirement. Chapters 7, 8, and 11 are general, and have no technical information explaining the drafting team’s actions.

4. The SSRG recommends the drafting team consider implementing all the redlines changes to the RSAW that have been identified in the other documents to promote consistency throughout their documentation process.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FFERC Order No. 830 (P. 97 and P.102) and FERC Order No. 851 (P. 54) state that NERC should consider extensions of time on a case-by-case basis. FERC Order 851 (P. 5 and P. 55) expands upon this by referring to submission "to NERC or a Regional Entity, as appropriate".

The SDT believes consistent timelines is the best practice for implementing TPL-007-4, non-hardware mitigations shall be completed within two years and hardware mitigations shall be completed within four years. In addition, the extension process will allow entities that encounter situations beyond their control to request extensions of time.

These requirements were revised as a result of FERC Order No. 851 (P. 56), which directs NERC to modify R7.4 by developing a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-by-case basis. Regarding the comment about including additional technical language, the SDT believes that the Technical Rationale document provides a reasonable level of technical detail. Note that supporting technical documents are provided in the Reference section of the Technical Rationale document. For additional technical explanation on the Supplemental GMD Event please see the Supplemental GMD Event Description white paper. The SDT is not responsible for the RSAW. The process accounts for incorporating the changes to the RSAW as draft standards are modified.

Anthony Jablonski - ReliabilityFirst – 10	
Answer	
Document Name	
Comment	
ReliabilityFirst has identified a change in Requirement R1 that was not captured in the redline. When Requirement R1 was copied over to TPL-007-4, the SDT dropped the word "area" from the requirement. As is, the Requirement does not seem to make sence. Please note (in bold text) the updated requirement below: *Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning **area** for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to express our thanks for pointing out the typo in Requirement R1, it has been corrected.	

Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	
Document Name	
Comment	
The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment. ACES appreciates the efforts of drafting team members and NERC staff in continuing to enhance the standards for the benefit of reliability of the BES.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment.
Scott McGough - Georgia System Operations Corporation - 3,4

Answer	
Document Name	

Comment
The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	
Document Name	

Comment
ISO-NE believes that the additional guidance provided in chapter 8 of the draft Transmission System Planned Performance for Geomagnetic Disturbance Events Implementation guidance document for simulating the supplemental GMD event is very helpful. ISO recommends reviewing the language in that chapter to ensure consistency with the purpose of the implementation guidance document as explained in

the first paragraph of its Introduction section (i.e. make clear that the information provided describes an example of how the standard's requirements could be met), and not infer the introduction of additional requirements which would not otherwise be contained in the TPL-007 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Chapter 8 of the Implementation Guidance document has been updated to reflect ISO-NE's comment.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	
Document Name	
Comment	
The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC to regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES. Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Steven Dowell - Alcoa - Alcoa, Inc. - 7	
Answer	
Document Name	
Comment	
Alcoa would like to abstain. Alcoa would urge the SDT to examine cost/benefit analysis for implementation of GMDs at non-critical facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the commenter’s suggestion is outside the scope of this SDT.	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard is drafted in the manner that the vulnerability assessment and CAP development for the benchmark and supplemental events are defined in separate sequential requirements in order to keep the standard language clear and avoid misinterpretation. Since TPL-007-3 is an active standard and responsible entities are currently performing the pertinent studies, the SDT decided to preserve the numbering structure in TPL-007-3 to minimize the disruption existing processes and documentation.	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	
Document Name	
Comment	
As inverter based sources of generation increase on the grid, the requirements of IEEE-Std-519 related to THD percentages (to the 40th harmonic) may need to be revisited. Energy at higher order harmonic frequencies has been observed at bulk (>20 MW) solar sites, which may increase potential for thermal saturation in banks that would otherwise not be susceptable to GIC. Although separate from the specific guidance in this TPL, this may represent a sensitivity factor that could be weighted as part of the overall security assessment of the banks being reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TPL-007 is a performance standard which asks entities to take into account the impact of harmonics.	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don’t use CMEP Implementation Guidance to establish requirements which go	

beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following:

•   "The local geoelectric field enhancement should not be smaller than 100 km.."- this threshold value of 100 km does not appear in the standard requirement

•   "…at a minimum, a West-East orientation should be considered when applying the supplemental event"- the standard requirement does not contain any wording of a minimum consideration

•   "Geoelectric field outside the local enhancement:

a. Amplitude: should not be smaller than 1.2 V/km…" This also does not appear in the standard.

•   "The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event". This statement creates boundaries outside of requirements, which guidance cannot do.

The use of "shall" or "must" should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional "requirement".

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT updated the Implementation Guidance document to incorporate this feedback.

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 1, 3; Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Louis Guidry

Answer	
Document Name	

Comment	
Cleco does agree with the concept, the language, particularly with regard to the extent of the Corrective Action Plan (R11) and various timetable requirements are overreaching and place undue burden on potentially affected entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R11 was added by the SDT to address the FERC directive in Order No. 851 (Paragraphs 4 and 39 of the Order) which requires CAPs for the vulnerabilities identified in the supplemental GMD analysis.	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT provided comments to CMEP staff and believes that the revised draft process prepared by CMEP staff may address many of your concerns.	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

We don't need to remind the Project 2019-01 SDT that this will be the fourth version of the TPL-007 Reliability Standard in three years. The team has done a fine job of meeting the directives of FERC Order No. 851, but we encourage the SDT to push back harder on the corrective action implementation timeframes for the supplemental GMD event. From a holistic view, this effort to address vulnerability to GMD events appears to be getting too far ahead of good, robust science and engineering. The industry simply does not have mature hardware solutions available to potentially mitigate GIC issues, anticipated from mathematical model simulation software packages that are updating at least as frequently as the TPL-007 standard itself has changed, while constantly chasing the emerging GMD science. The reliability of the BES is, and will be, best served by the improved awareness of GMD impacts embodied by the TPL-007, as well as operator responsiveness required by EOP-010-1. The existing required identification of corrective actions is key; just give industry the time and flexibility to adopt solutions that suit them best.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP thanks the standards drafting team for their efforts on this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
The Standard Draft Team (SDT) has added language to submit requests for extensions of timeframes to the ERO, i.e., NERC, for approval. Seminole reasons that individual entities should communicate such requests to the RRO, e.g., SERC, WECC, etc., and that the individual RRO should approve/deny such requests instead of NERC. Seminole is requesting the language be revised to capture this.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in R7.4 and R11.4 has been modified to clarify intent.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

As previously stated, many of the obligations within TPL-007, both existing and proposed, precede industries' full understanding of GMD and its true, discernable impacts. This proves challenging when attempting to develop standards to adequately address the perceived risks. We support, and are appreciative of, the efforts of the standards drafting team and their desire to address the directives issued in Order No. 851, however we believe the spirit of those directives can be met without pursuing a path that duplicates obligations already required for the benchmark event. We believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude (one not determined solely by non-spatially averaged data) for a single GMD Vulnerability Assessment (benchmark) that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES. Due to the concerns we have expressed above, AEP has chosen to vote negative on the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that analyzing both benchmark and supplement events is the scientifically justified approach to the study of GMD events that is not based solely on spatially averaged data. See Benchmark and Supplemental GMD Event White Papers. FERC order 851 requires the SDT to develop a CAP for supplemental event: "The Commission also directs NERC to develop and submit modifications to Reliability Standard TPL-007-2: (1) to require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities;……" The SDT has elaborated on the supplement event to the Implementation Guidance document.	
Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2019-01 Modifications to TPL-007-3

Ballot Pools Forming through August 26, 2019
Formal Comment Period Open through September 9, 2019

Now Available

A 45-day formal comment period for **TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern, Monday, September 9, 2019.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues using the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, August 26, 2019.** Registered Ballot Body members can join the ballot pools here.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An Initial ballot for the standard, along with non-binding polls for the associated Violation Risk Factors and Violation Severity Levels, will be conducted **August 30 – September 9, 2019.**

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify “Project 2019-01 Modifications to TPL-007-3 Observer List” in the Description Box. For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/176)
Ballot Name: 2019-01 Modifications to TPL-007-3 TPL-007-4 IN 1 ST
Voting Start Date: 8/30/2019 12:01:00 AM
Voting End Date: 9/9/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 267
Total Ballot Pool: 292
Quorum: 91.44
Quorum Established Date: 9/9/2019 12:57:54 PM
Weighted Segment Value: 70.84

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	43	0.694	19	0.306	0	10	10
Segment: 2	6	0.4	3	0.3	1	0.1	0	1	1
Segment: 3	67	1	35	0.673	17	0.327	0	11	4
Segment: 4	13	1	8	0.727	3	0.273	0	1	1
Segment: 5	65	1	32	0.64	18	0.36	0	8	7
Segment: 6	49	1	24	0.558	19	0.442	0	4	2
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	292	6.2	153	4.392	77	1.808	0	37	25

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Donald Lynd		Abstain	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Dairyland Power Cooperative	Renee Leidel		Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Ayman Samaan		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Trey Melcher		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Adrianne Collins		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Third-Party Comments
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		None	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Third-Party Comments
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Nicholas Tenney		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy	Jamie Prater		Negative	Comments Submitted
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Linda Horn		Negative	Third-Party Comments
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Hathaway		Negative	Third-Party Comments
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Western Area Power Administration	Rosemary Jones		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 292 of 292 entries

BALLOT RESULTS

Ballot Name: 2019-01 Modifications to TPL-007-3 TPL-007-4 Non-binding Poll IN 1 NB
Voting Start Date: 8/30/2019 12:01:00 AM
Voting End Date: 9/9/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 277
Quorum: 88.81
Quorum Established Date: 9/9/2019 1:14:18 PM
Weighted Segment Value: 71.04

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	74	1	36	0.75	12	0.25	17	9
Segment: 2	5	0.4	4	0.4	0	0	0	1
Segment: 3	66	1	31	0.738	11	0.262	18	6
Segment: 4	12	0.9	6	0.6	3	0.3	2	1
Segment: 5	62	1	28	0.7	12	0.3	12	10
Segment: 6	48	1	18	0.545	15	0.455	11	4
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	2	0
Totals:	277	6	130	4.434	53	1.566	63	31

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Donald Lynd		Abstain	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Dairyland Power Cooperative	Renee Leidel		Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Ayman Samaan		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Trey Melcher		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Adrianne Collins		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Vivian Moser		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Austin Energy	Jun Hua		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Nicholas Tenney		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy	Jamie Prater		None	N/A
5	Exelon	Cynthia Lee		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Exelon	Becky Webb		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		Negative	Comments Submitted
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Western Area Power Administration	Rosemary Jones		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the final draft of proposed standard for formal 10-day final ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019
45-day formal comment period with ballot	August 30 – September, 9 2019

Anticipated Actions	Date
10-day final ballot	November 2019
Board adoption	February 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-4
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.2.** Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.3.** Transmission Owner who owns a Facility or Facilities specified in 4.2; and
     - **4.1.4.** Generator Owner who owns a Facility or Facilities specified in 4.2.
   - **4.2. Facilities:**
     - **4.2.1.** Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. **Effective Date:** See Implementation Plan for TPL-007-4.
6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R12 and R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \, (V/km) \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_s \, (V/km) \quad (2)$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \quad (3)$$

where, L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$.

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[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

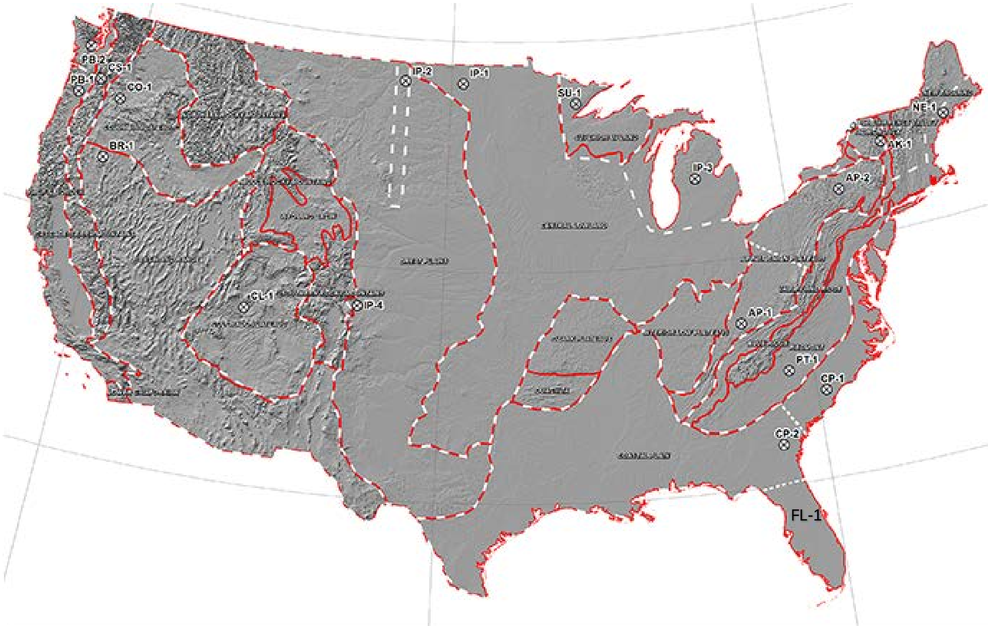

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors

Earth model	Scaling Factor Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

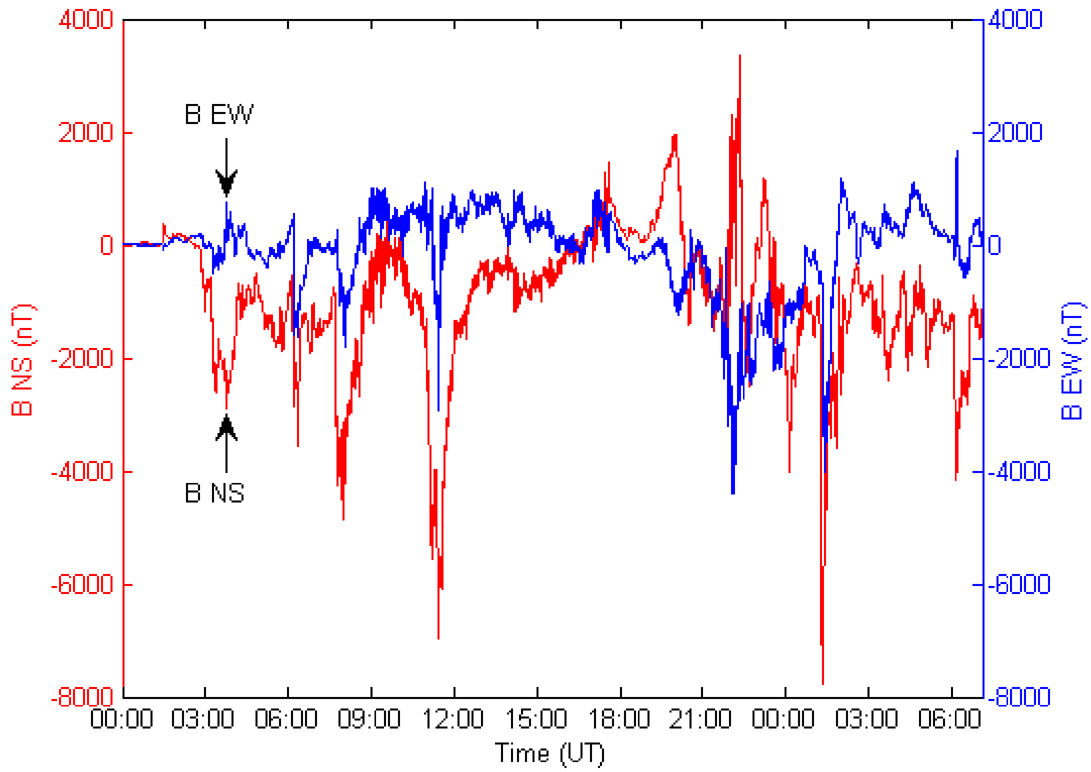

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

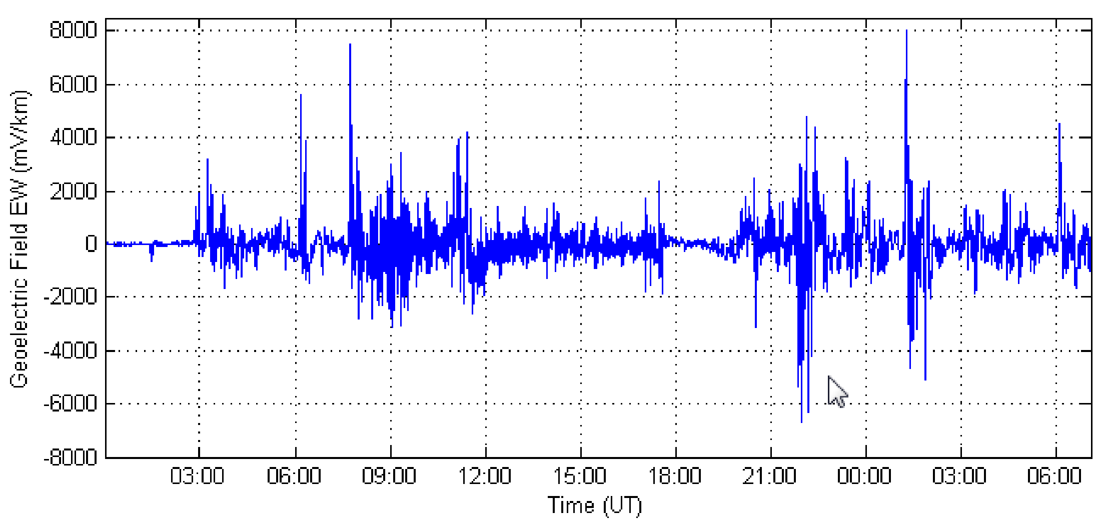

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

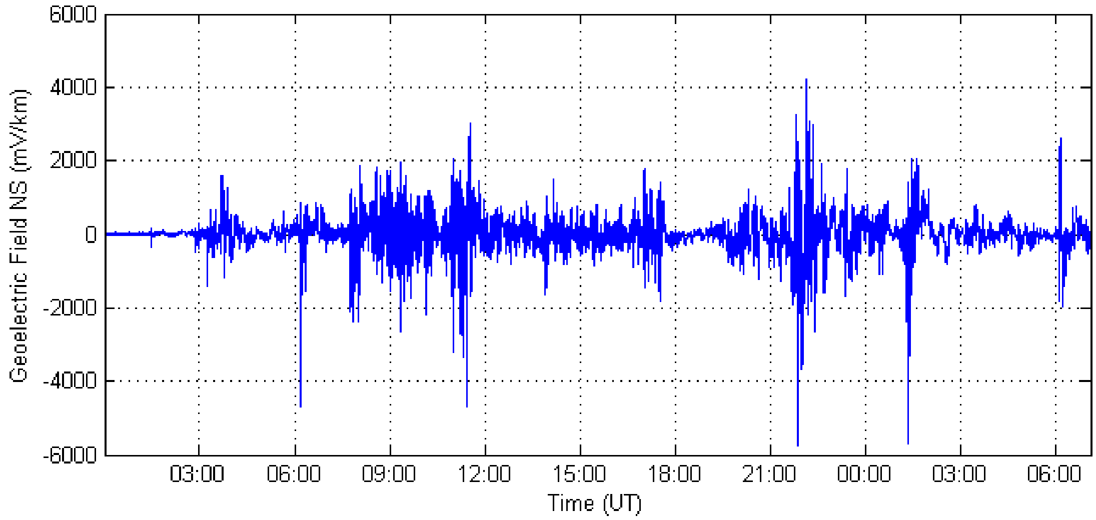

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

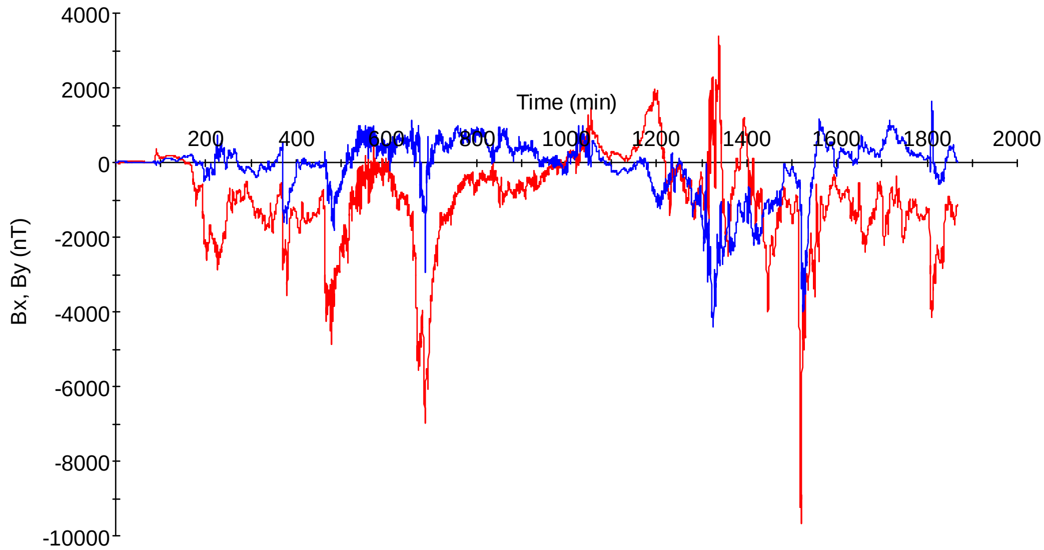

Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

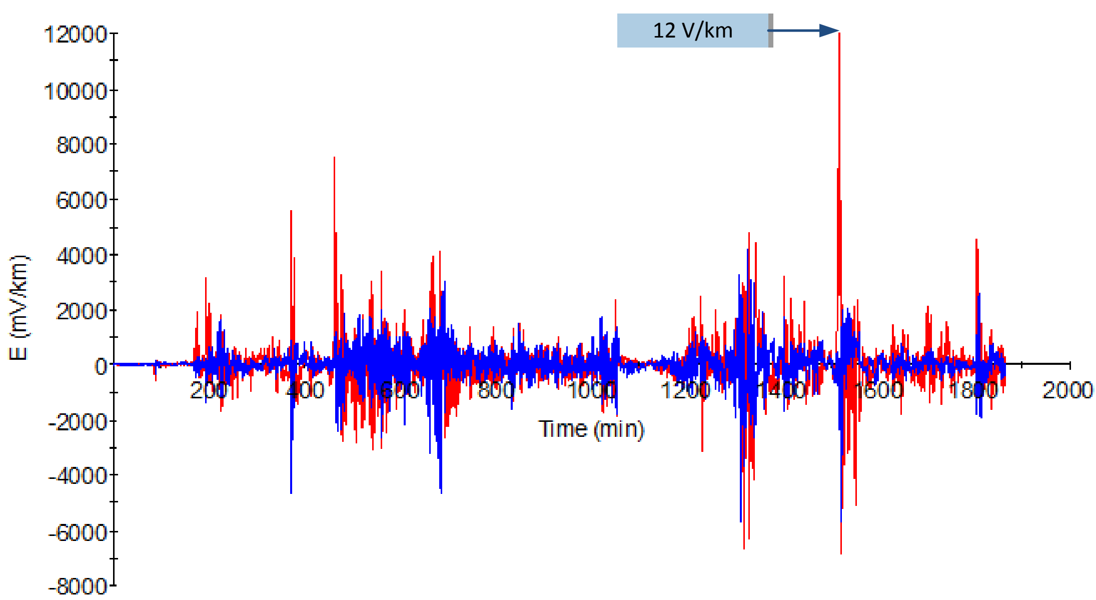

Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The “earth transfer function” is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the ~~first~~final draft of proposed standard for formal ~~45~~10-day final ballot~~comment~~ period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019
45-day formal comment period with ballot	August 30 – September, 9 2019

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~July – September 2019~~
~~45-day formal comment period with additional ballot~~	~~October – December 2019~~
~~45-day formal comment period with second additional ballot~~	~~January – March 2020~~
10-day final ballot	~~April~~ November 2019~~20~~
Board adoption	~~May~~February 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-4

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

   4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-4.

6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~ERO~~ approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the Compliance Enforcement Authority (CEA)~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA~~ERO~~ if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ~~ ERO~~ approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA~~ERO~~ with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA~~ERO~~ if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R12 and R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \,(V/km) \tag{1}$$

$$E_{peak} = 12 \times \alpha \times \beta_s \,(V/km) \tag{2}$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \tag{3}$$

where, L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the ~~planning~~responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

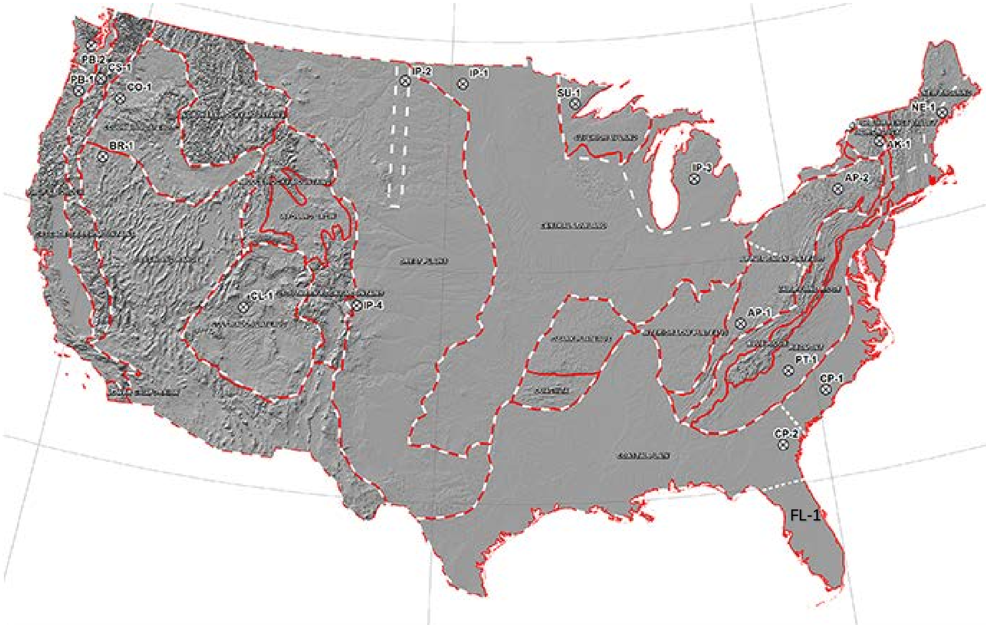

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

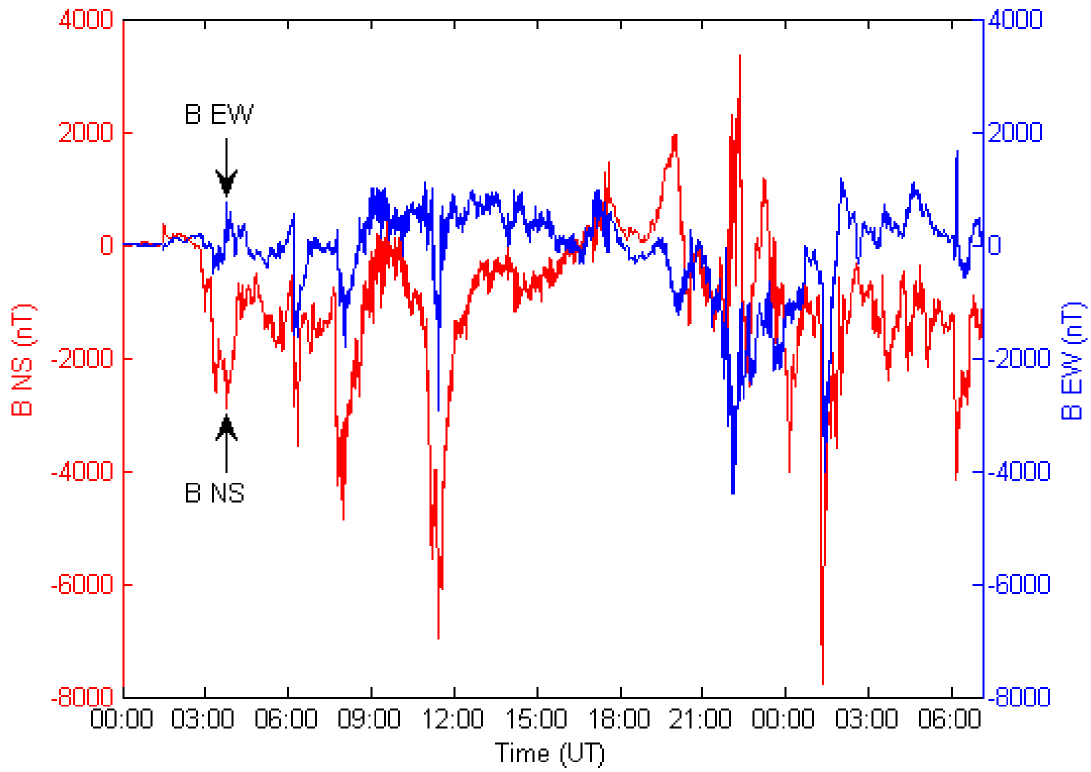

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

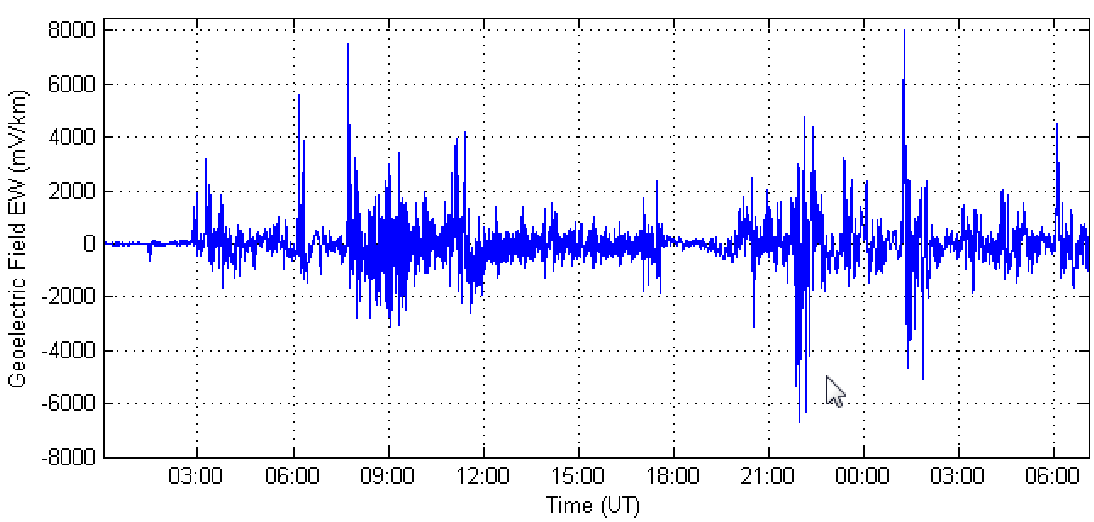

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

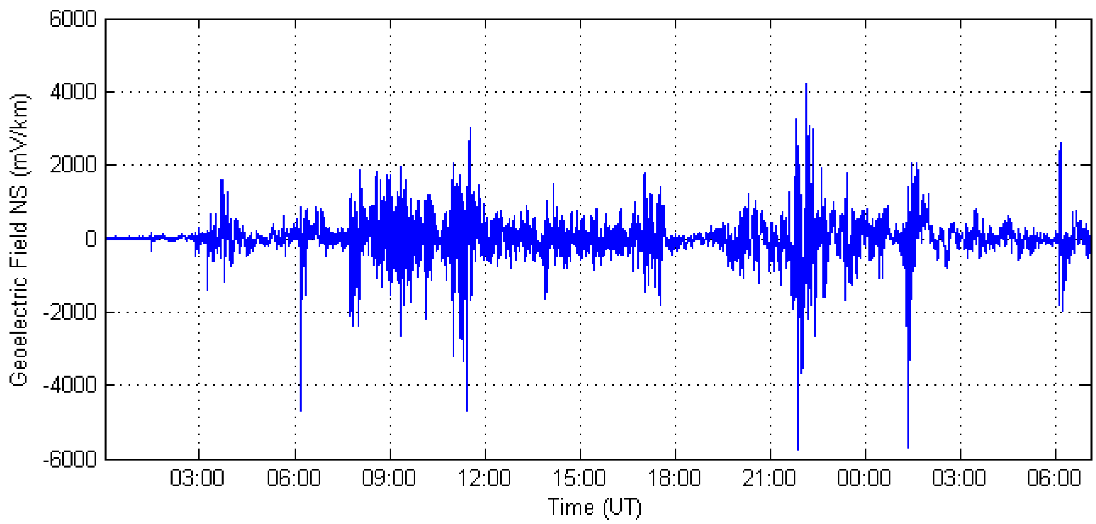

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

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[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

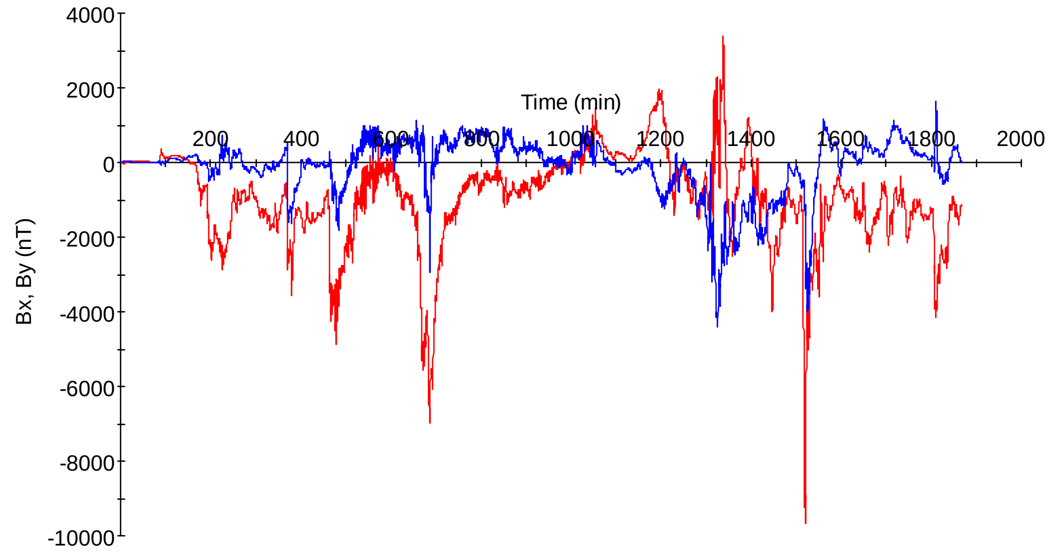

Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

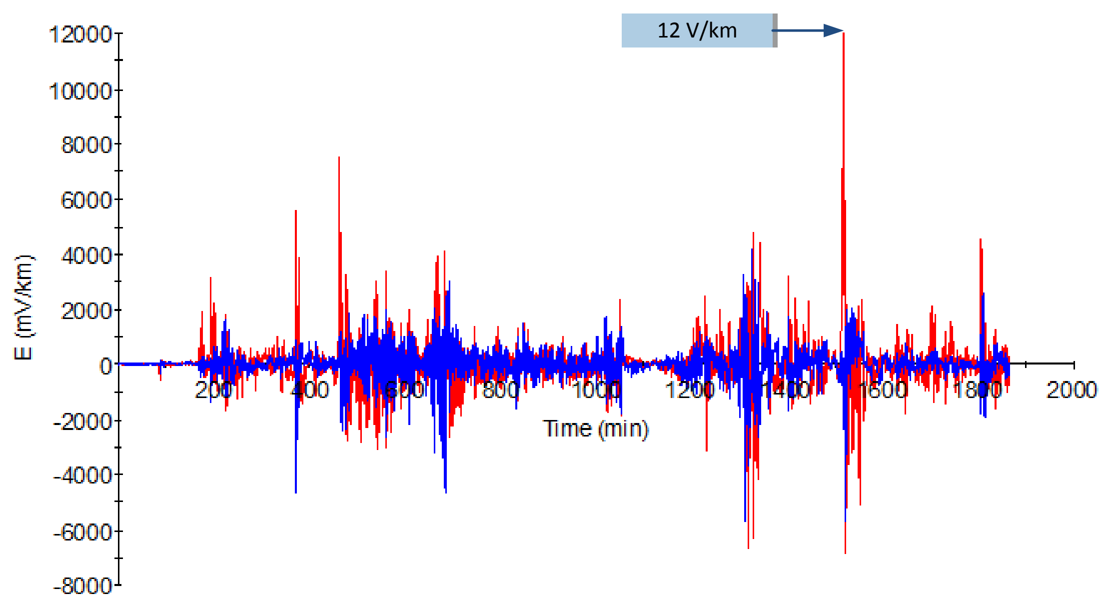

Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the final draft of proposed standard for formal 10-day final ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019
45-day formal comment period with ballot	August 30 – September, 9 2019

Anticipated Actions	Date
10-day final ballot	November 2019
Board adoption	February 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-~~3~~4
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.2.** Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.3.** Transmission Owner who owns a Facility or Facilities specified in 4.2; and
     - **4.1.4.** Generator Owner who owns a Facility or Facilities specified in 4.2.
   - **4.2. Facilities:**
     - **4.2.1.** Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. **Effective Date:** See Implementation Plan for TPL-007-~~3~~4.
6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

~~The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of that in TPL-007-2.~~

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~revision by the responsible entity in~~approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be ~~revised if situations beyond~~submitted to the ~~control~~Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity ~~determined in Requirement R1 prevent implementation of~~is unable to implement the CAP within the timetable ~~for implementation~~ provided in Part 7.3. The ~~revised~~submitted CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

~~**7.4.2.** Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~

~~**7.4.3.**~~**7.4.2.** Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable~~,~~; and ~~the updated timetable for implementing the selected actions.~~

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the ~~results~~CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it ~~has revised its CAP~~submitted a request for extension to the CEA if ~~situations beyond~~ the responsible ~~entity's control prevent implementation of~~entity is unable to implement the CAP within the timetable ~~specified.~~provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

~~**8.3.** If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.~~

~~**8.4.**~~**8.3.** The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

~~**8.4.1.**~~**8.3.1.** If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

~~R11.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M11.~~M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement ~~R11~~R12.

~~R12.~~R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M12.~~M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement ~~R12~~R13.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements ~~R11~~R12 and ~~R12~~R13, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event ~~-~~– GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		months since the last benchmark GMD Vulnerability Assessment.	months since the last benchmark GMD Vulnerability Assessment.	benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not ~~have~~develop a Corrective Action Plan as required by Requirement R7.
R8.	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;~~ ~~OR~~ The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~two~~one of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~three~~two of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy ~~four~~three of the elements listed in Requirement R8, Parts 8.1 through 8.~~4~~3; OR The responsible entity completed a supplemental GMD Vulnerability

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment	The responsible entity failed to conduct a supplemental thermal impact assessment

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1	for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1;	for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	OR The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R11~~R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
~~R12~~R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

~~All~~This variance replaces all references to "Attachment 1" in the standard ~~are replaced~~ with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \, (V/km) \tag{1}$$

$$E_{peak} = 12 \times \alpha \times \beta_s \, (V/km) \tag{2}$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \tag{3}$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

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

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the ~~planning~~responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

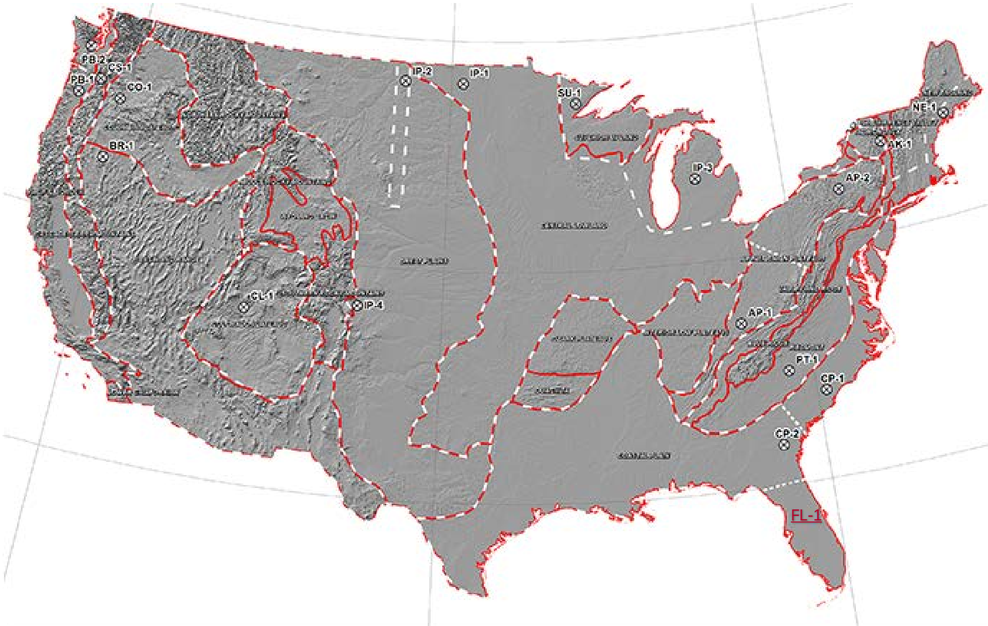

Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

~~**Rationale:** Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.~~

~~The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated based on the earth model published on the USGS public website.~~

Table 4: Reference Earth Model (Quebec)

Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

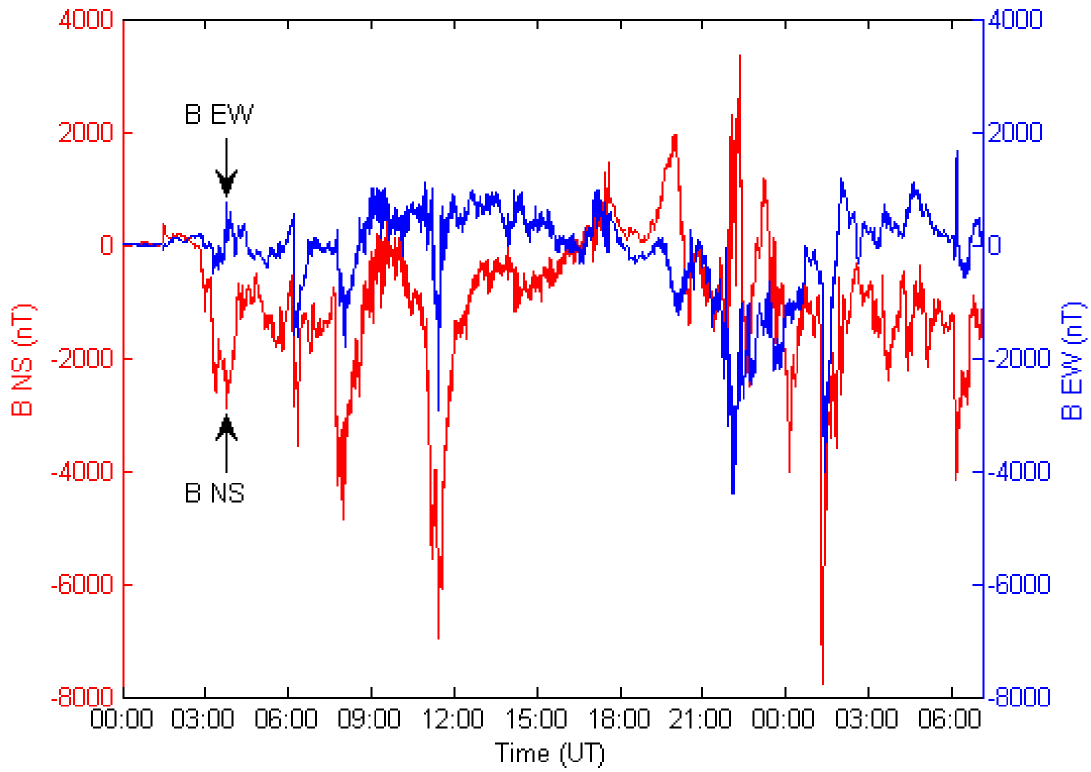

Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

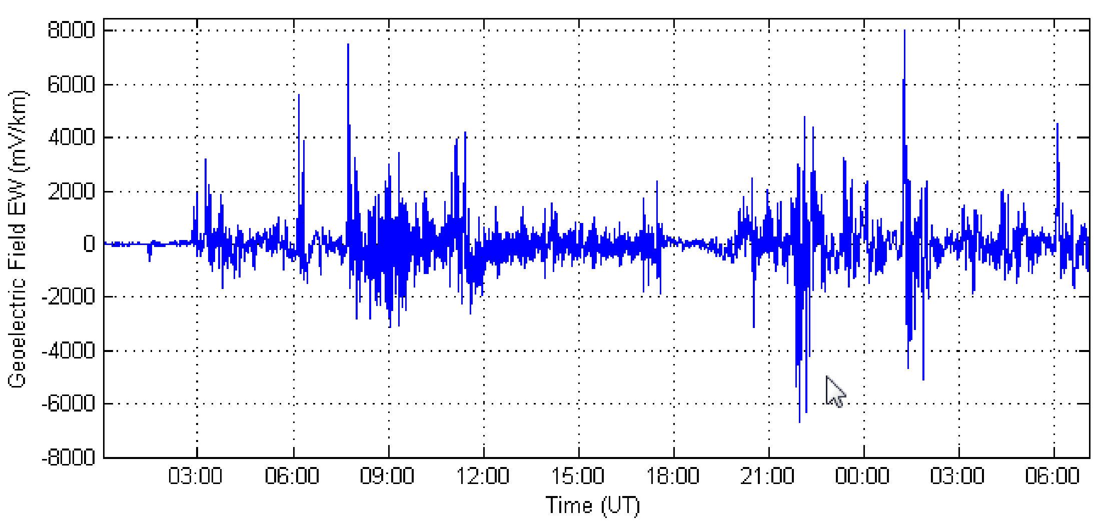

Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

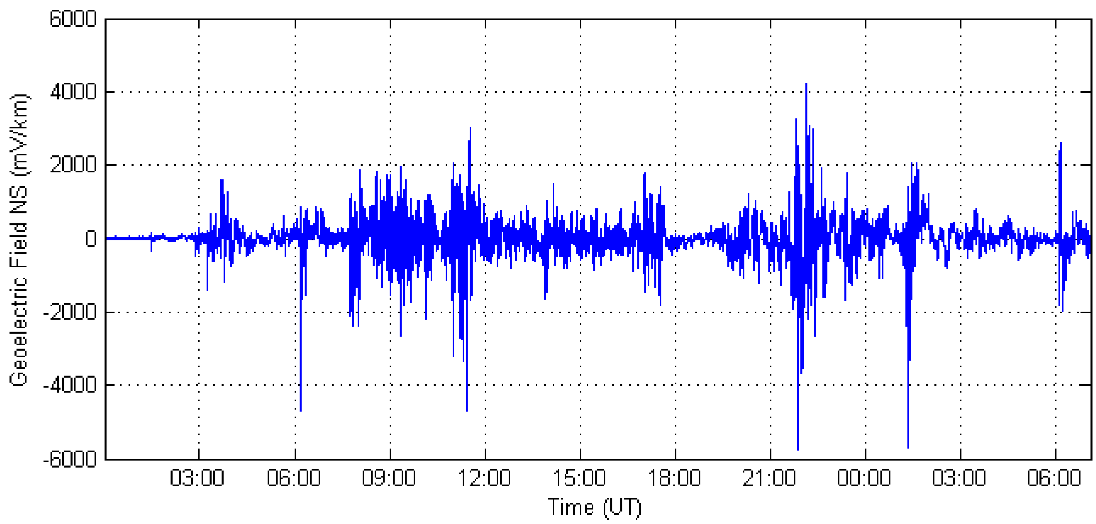

Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

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[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

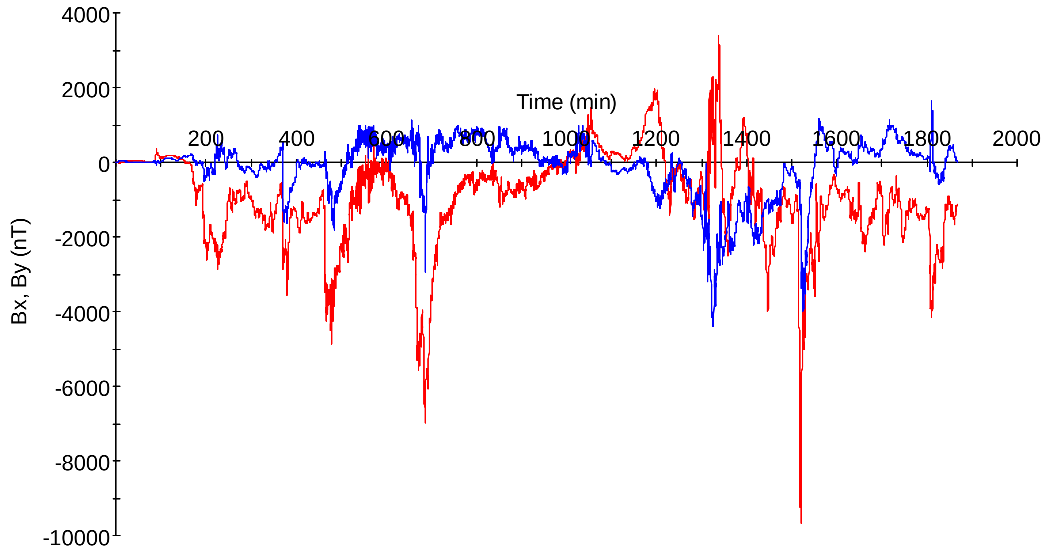


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

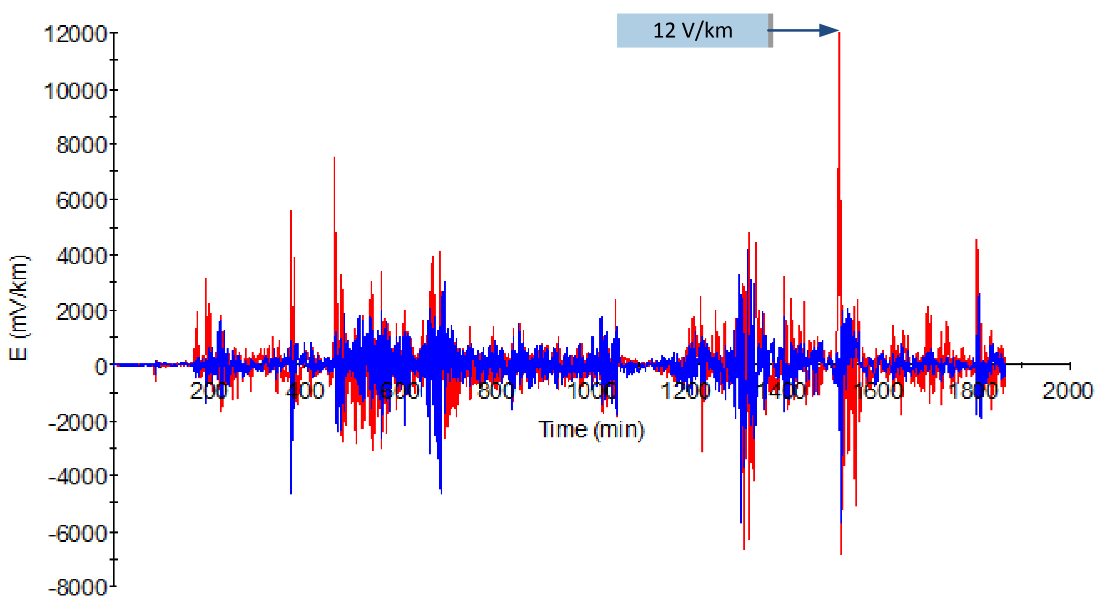


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).~~[1]~~[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

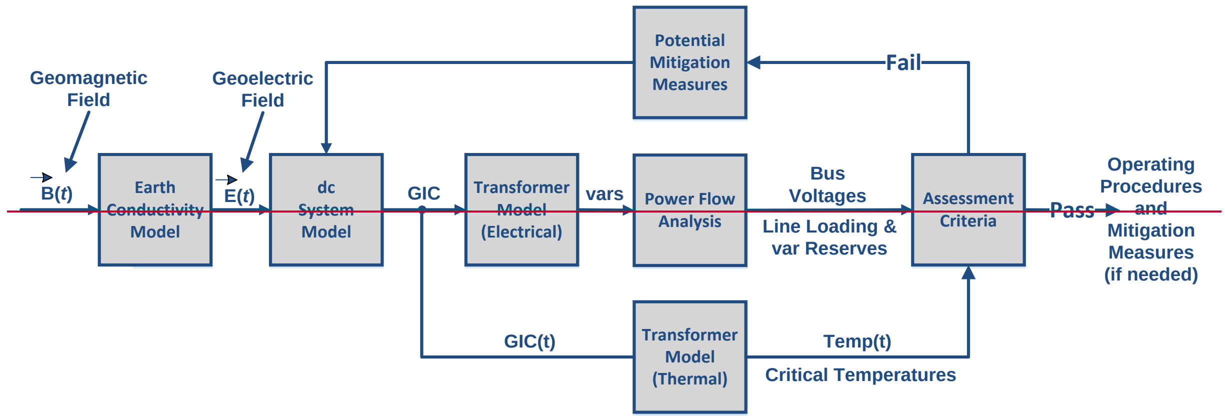
~~[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.~~

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

~~Guidelines and Technical Basis~~

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



~~The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.~~

~~Benchmark GMD Event (Attachment 1)~~

~~The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016[11] white paper includes the event description, analysis, and example calculations.~~

~~Supplemental GMD Event (Attachment 1)~~

~~The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017[12] white paper includes the event description and analysis.~~

~~Requirement R2~~

~~A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*, December 2013.[13]~~

~~Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the~~

~~[11] http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.~~

~~[12] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.~~

~~conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.~~

~~Requirement R4~~

~~The *Geomagnetic Disturbance Planning Guide*,[14] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~Requirement R5~~

~~The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.~~

~~GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time-series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the *Transformer Thermal Impact Assessment White Paper*,[15] October 2017.~~

~~The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R6~~

~~The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed*~~

~~[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~[15] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~*Implementation Guidance*[16] for this requirement. This ERO-Endorsed document is posted on the NERC Compliance Guidance[17] webpage.~~

~~Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[18] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.~~

~~The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R7~~

~~Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*,[19] December 2013. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[20] February 2012.~~

~~Requirement R8~~

~~The *Geomagnetic Disturbance Planning Guide*,[21] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.~~

~~The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.~~

~~Requirement R9~~

~~The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~[16] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~
~~[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx.~~
~~[18] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
~~[19] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~
~~[20] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~
~~[21] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~

~~The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.~~

~~GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.~~

~~The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.~~

~~Requirement R10~~

~~The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[22] discussed in the Requirement R6 section above. A later version of the *Transformer Thermal Impact Assessment White Paper*,[23] October 2017, has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment.~~

~~Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[24] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.~~

~~The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.~~

~~Requirement R11~~

~~Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*,[25] February 2012. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful for model validation and situational awareness.~~

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[22] ~~http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.~~

[23] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

[24] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

[25] ~~http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.~~

~~Responsible entities consider the following in developing a process for obtaining GIC monitor data:~~

- ~~**Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.~~

- ~~**Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.~~

- ~~**Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.~~

- ~~**Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.~~

- ~~**Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.~~

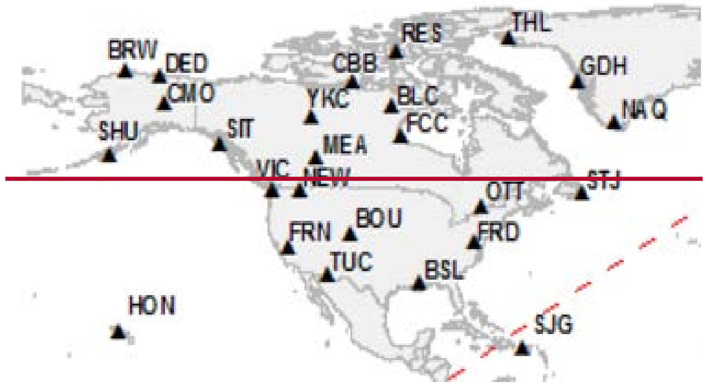
- ~~**Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.~~

- ~~**Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).~~

~~Requirement R12~~

~~Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:~~

- ~~Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:~~[26]



- ~~Research institutions and academic universities;~~
- ~~Entities with installed magnetometers.~~

~~Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012.~~[27]

[26] ~~http://www.intermagnet.org/index-eng.php.~~
[27] ~~http://www.intermagnet.org/publications/intermag_4-6.pdf.~~

~~Rationale~~

~~During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].~~

~~Rationale for Applicability:~~

~~Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.~~

~~Terminal voltage describes line-to-line voltage.~~

~~Rationale for R1:~~

~~In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).~~

~~Rationale for R2:~~

~~A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the~~ ~~*Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System*~~~~,[28] December 2013, developed by the NERC GMD Task Force.~~

~~The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.~~

~~The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.~~

~~The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.~~

~~The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (Docket No. RM12-1-000). NERC guidelines require consistency among Reliability Standards.~~

~~[28] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.~~

~~**Rationale for R3:**~~
~~Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.~~

~~**Rationale for R4:**~~
~~The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.~~

~~At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.~~

~~Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.~~

~~The *Geomagnetic Disturbance Planning Guide*,[29] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~**Rationale for R5:**~~
~~This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.~~

~~The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.~~

~~GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*,[30] October 2017.~~

~~A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but~~

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[29] ~~http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.~~
[30] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.~~

~~The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~Rationale for R6:~~

~~The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[31] October 2017.~~

~~The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper*,[32] October 2017.~~

~~Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.~~

~~Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.~~

~~The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.~~

~~Rationale for R7:~~

~~The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P 102):~~

- ~~Two years for non-hardware mitigation; and~~
- ~~Four years for hardware mitigation.~~

~~The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part~~

[31] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~
[32] ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.~~

~~7.3. Examples of situations beyond the control of the of the responsible entity (see Section 7.4) include, but are not limited to:~~

- ~~Delays resulting from regulatory/legal processes, such as permitting;~~
- ~~Delays resulting from stakeholder processes required by tariff;~~
- ~~Delays resulting from equipment lead times; or~~

~~Delays resulting from the inability to acquire necessary Right-of-Way.~~

~~Rationale for Table 3:~~

~~Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74. [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]~~

~~Rationale for R8 – R10:~~

~~The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P 44, P 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.~~

~~Rationale for R11 – R12:~~

~~The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88; P. 90-92). GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R11 and R12, respectively. See the Guidelines and Technical Basis section of this standard for technical information.~~

~~The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.~~

~~The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:~~

- ~~Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;~~
- ~~Installed magnetometers; and~~
- ~~Commercial or third-party sources of geomagnetic field data.~~

~~Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.~~

Implementation Plan

Project 2019-01 Modifications to TPL-007-3

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. No continent-wide requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

General Considerations

This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard TPL-007-4

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1, R2, R5, and R9

Entities shall be required to comply with Requirements R1, R2, R5, and R9 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R12 and R13

Entities shall not be required to comply with Requirements R12 and R13 until the later of: (i) July 1, 2021; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the later of: (i) January 1, 2022; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R3, R4, and R8

Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7

Entities shall not be required to comply with Requirement R7 until the later of: (i) January 1, 2024; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R11

Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.

Retirement Date

Standard TPL-007-3

Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission System Planned Performance for Geomagnetic Disturbance Events

Technical Rationale and Justification for Reliability Standard TPL-007-4

November 2019

RELIABILITY | RESILIENCE | SECURITY

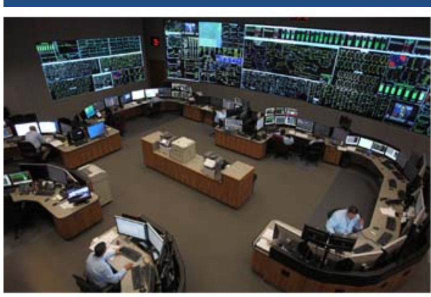


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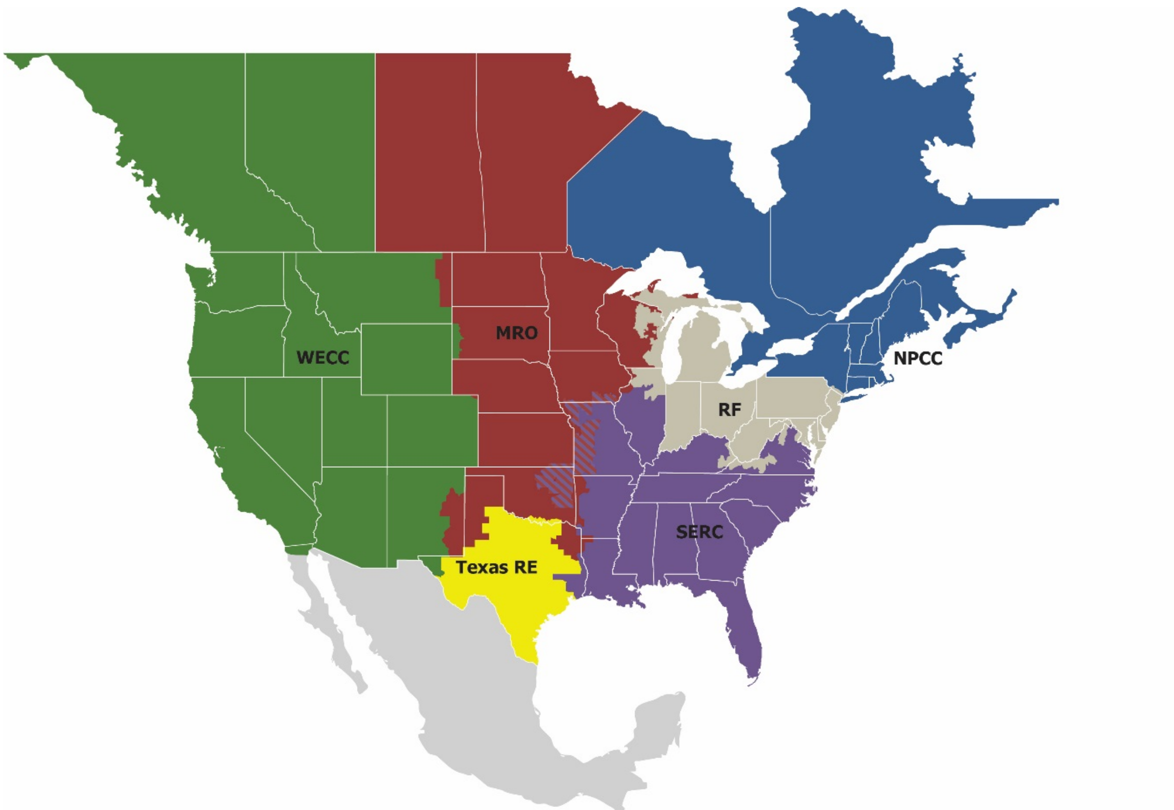
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. It also contains information on the standard drafting team's intent in drafting the requirements. This document, the Technical Rationale and Justification for TPL-007-4, is not a Reliability Standard and should not be considered mandatory and enforceable.

The first version of the standard, TPL-007-1, approved by FERC in Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect Canadian-specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version of the standard, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 with a process through which extensions of time are considered on a case-by-case basis (P 54).

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process. Figure 1 provides an overall view of the GMD Vulnerability Assessment process:

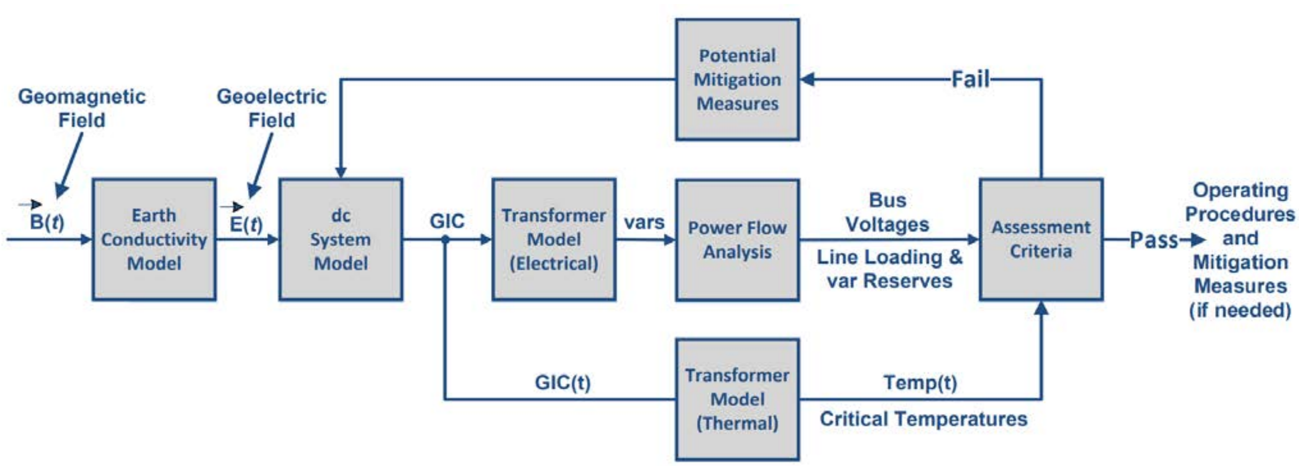


Figure 1. GMD Vulnerability Assessment Process.

General Considerations

Rationale for Applicability

Reliability Standard TPL-007-4 is applicable to Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these types of transformers are not included in the applicability for this standard. Terminal voltage describes line-to-line voltage.

Benchmark GMD Event (TPL-007-4 Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016 [4], includes the event description, analysis, and example calculations.

Supplemental GMD Event (TPL-007-4 Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017 [5], includes the event description and analysis.

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model are provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

System models specified in Requirement R2 are used in conducting steady state power flow analysis, that accounts for the Reactive Power absorption of power transformer(s) due to GIC flow in the System, when performing GMD Vulnerability Assessments. Additional System modeling considerations could include facilities less than 200 kV.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

Requirement R4

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load shall be included in the in the study or studies (see Requirement R4).

Requirement R5

The benchmark thermal impact assessment of transformers, specified in Requirement R6, is based on GIC information for the benchmark GMD Event. This GIC information is determined by the responsible entity through simulation of the GIC System model and shall be provided to the entity responsible for conducting the thermal impact assessment (see Requirement R5). GIC information for the benchmark thermal impact assessment should be provided in accordance with Requirement R5 each time the benchmark GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 75 A per phase, in the benchmark GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the benchmark thermal impact of GIC on transformers in the planning area and shall be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment (see Requirement R5). GIC information should be provided in accordance with Requirement R5 as part of the benchmark GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 5.2 can be used to convert the steady state GIC flows to time-series GIC data for the benchmark transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Requirement R6

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the responsible entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.

Thermal assessments for transformers with a high side, grounded-wye winding greater than 200 kV are required because the damage of these types of transformers may have an effect on the wide-area reliability of the interconnected Transmission System.

Requirement R7

This requirement addresses directives in FERC Order No. 851 to replace the time-extension provision in Requirement R7.4 of TPL-007-2 (and TPL-007-3) with a process through which extensions of time are considered on a case-by-case basis.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Supplemental GMD Vulnerability Assessment

The requirements, R8-R11, address directives in FERC Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (PP 44, 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Requirement R8

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load shall be included in the study or studies (see Requirement R8).

Requirement R9

The supplemental thermal impact assessment of transformers, specified in Requirement R10, is based on GIC information for the supplemental GMD Event. This GIC information is determined by the responsible entity through simulation of the GIC System model and shall be provided to the entity responsible for conducting the thermal impact assessment (see Requirement R9). GIC information for the supplemental thermal impact assessment should be provided in accordance with Requirement R9 each time the supplemental GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 85 A per phase, in the supplemental GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the supplemental thermal impact of GIC on transformers in the planning area and shall be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment (see Requirement R9). GIC information should be provided in accordance with Requirement R9 as part of the supplemental GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 9.2 can be used to convert the steady state GIC flows to time-series GIC data for the supplemental transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [10].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the responsible entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R9.

Thermal assessments for transformers with a high side, grounded-wye winding greater than 200 kV are required because the damage of these types of transformers may have an effect on the wide-area reliability of the interconnected Transmission System.

Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for the assessed supplemental GMD event vulnerabilities.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the Geomagnetic Disturbance Planning Guide, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Requirement R12

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect GIC monitoring data as necessary to enable model validation and situational awareness (PP 88, 90-92).

Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9]. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer and measure dc current flowing through the neutral. Data from GIC monitors is useful for model validation and situational awareness.

The objective of Requirement R12 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [9].

Requirement R13

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect magnetometer data as necessary to enable model validation and situational awareness (PP 88, 90-92).

The objective of Requirement R13 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

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November 2019 - DRAFT Implementation Guidance
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Implementation Guidance for Reliability Standard TPL-007-4

November 2019

RELIABILITY | RESILIENCE | SECURITY




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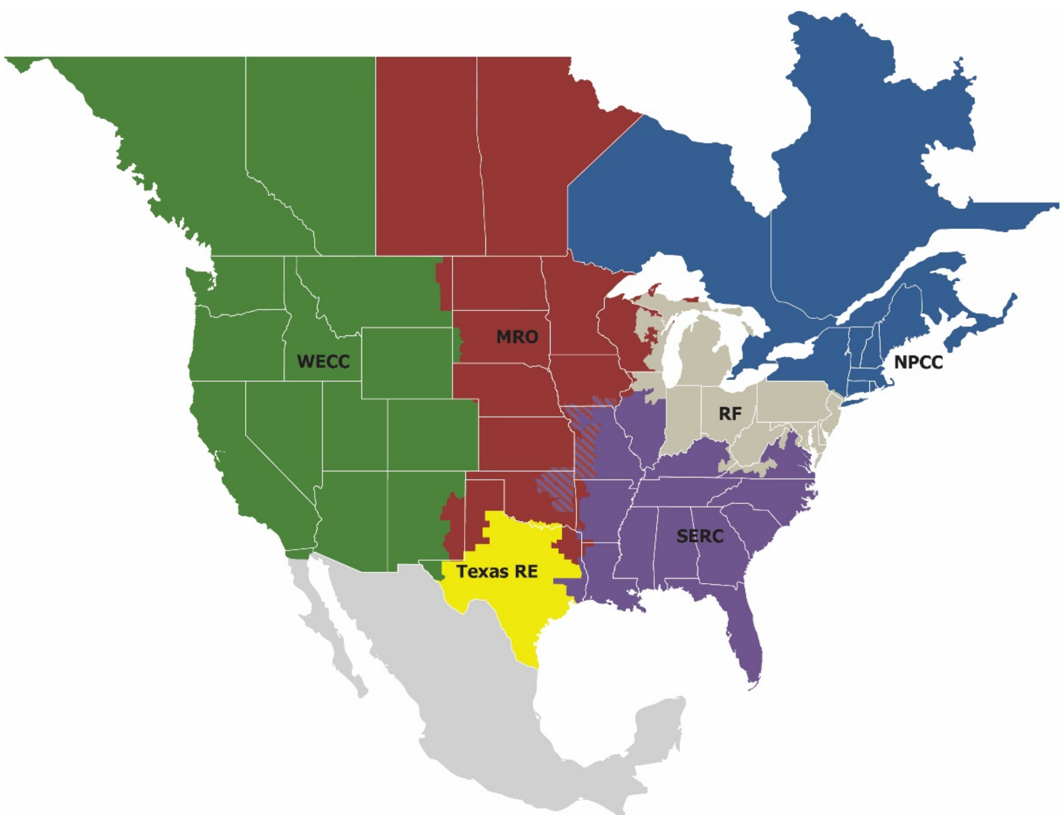
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

The Standards Project 2019-01 Modifications to TPL-007-3 standard drafting team prepared this Implementation Guidance to provide example approaches for compliance with the modifications to TPL-007 – Transmission System Planned Performance for Geomagnetic Disturbance Events. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches based on engineering judgement, individual equipment, and system conditions.

The first version of the standard, TPL-007-1 which was approved in FERC's Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Requirement R1

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Requirement R2

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These system adjustments could for example include recalling or postponing maintenance outages.

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. If applicable, include the above special modeling situations in the GIC System model.

Requirement R3

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1: Steady State Planning GMD Event found in TPL-007-4. Steady state voltage limits are an example of System steady state performance criteria.

Requirement R4

Distribution of benchmark GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Consider impact on neighboring systems when evaluating GIC study results.

Requirement R5

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the responsible entity. The responsible entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1 (see Requirement R5).

Requirement R6

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The benchmark thermal impact assessment shall be based on the effective GIC flow information (see Requirement R6). For additional information, refer to the above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5].

Approaches for conducting the thermal impact assessment of transformers for the benchmark event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the benchmark event are provided to the responsible entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (Requirement R4) and the Corrective Action Plan (CAP) (Requirement R7) as necessary.

Requirement R7

This requirement addresses directives in FERC Order No. 830 for establishing CAP deadlines associated with GMD Vulnerability Assessments. In FERC Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed NERC to establish implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 7.4 requires entities to submit to the CEA a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Supplemental GMD Vulnerability Assessment

The exact spatial extent, local time of occurrence, latitude boundary, number of occurrences during a GMD event, and geoelectric field characteristics (amplitude and orientation) inside/outside the local enhancement cannot yet be scientifically determined.

TPL-007-4 provides flexibility in applying the supplemental GMD event to the planning area. This guide provides examples of approaches and boundaries to apply the supplemental event based on what is presently understood on localized enhancements. As provided in the standard (Attachment 1) "Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event" may be used.

1. Spatial extent considerations:
    a. Apply a local geoelectric field enhancement consistent with available recordings of past events, e.g., greater than or equal to 100 km (West-East) by 100 km (North-South). Additional analysis may be performed by varying the spatial extent. Note that the 100 km North-South spatial extent is better understood than the West-East length, which could be 500 km or more; or
    b. Apply the peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) over the entire planning area. Note that this implies studying a GMD event rarer than 1-in-100 years.
2. Geoelectric field inside the local enhancement considerations:
    a. Amplitude: 12 V/km (scaled to the planning area); and
    b. Orientation: West-East (geomagnetic reference). Additional analysis may be performed varying the orientation of the geoelectric field.
3. Geoelectric field outside[1] the local enhancement consideration:
    a. Amplitude: Greater than or equal to 1.2 V/km (scaled to the planning area); i.e., an order of magnitude smaller than the field inside the local enhancement; and
    b. Orientation: West-East (geomagnetic reference). Additional analysis may be performed varying the orientation of the geoelectric field.
4. Position of the local enhancement considerations:
    a. Use engineering judgement to position the local enhancement on critical areas of the system. For example, the benchmark vulnerability assessment may identify areas with depressed voltages, lack of dynamic reactive reserves, large GIC flows through transformers, etc. Impacts to critical infrastructure or other externalities may also be considered; or
    b. Systematically move the position of the local enhancement throughout the entire planning area.

The schematic in Figure 1 illustrates an example of applying the supplemental GMD event. The local enhancement is 100 km by 100 km, the geoelectric field inside the local enhancement is 12 V/km (scaled to the planning area) with West-East orientation, and the geoelectric field outside the local enhancement is 1.2 V/km (scaled to the planning area) with a West-East orientation.

[1] The characteristics of the geoelectric field outside the local enhancement, for example amplitude, orientation, and spatial extent, are still being reviewed by the scientific community.

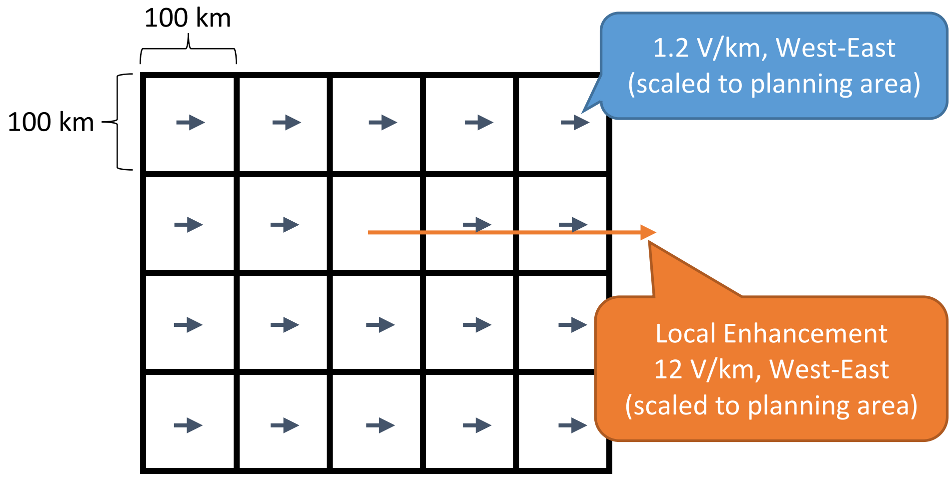


Figure 1. An Example of Applying the Supplemental Event.

Requirement R8

Distribution of supplemental GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Consider impact on neighboring systems when evaluating GIC study results.

Requirement R9

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the responsible entity. The responsible entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R9, Part 9.1 (see Requirement R9).

Requirement R10

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The supplemental thermal impact assessment shall be based on the effective GIC flow information (see Requirement R10). For additional information, refer to the above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5].

Approaches for conducting the thermal impact assessment of transformers for the supplemental event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the supplemental event are provided to the responsible entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R8) and the Corrective Action Plan (R11) as necessary.

Requirement R11

This requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for assessed supplemental GMD event vulnerabilities. This requirement is analogous to Requirement R7, such that CAPs are developed within one year from the completion of supplemental GMD Vulnerability Assessments and establishes implementation deadlines after the completion of the CAP as follows:

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 11.4 requires entities to submit to the CEA a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 11.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Requirement R12

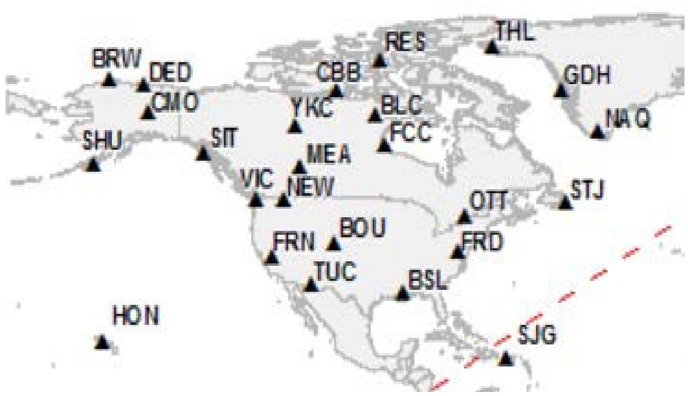
Responsible entities can consider the guidance found in NERC Rules of Procedure Section 1600 Data Request for the collection of GMD Data.[2]

[2] As of November 2019, a draft copy can be found at: https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_Data_Reporting_Instruction_draft.docx

Requirement R13

Responsible entities can consider the guidance found in NERC Rules of Procedure Section 1600 Data Request for the collection of GMD Data.[3]

The following map shows locations of magnetometers operated by U.S. Geological Survey (USGS) and Natural Resources Canada (NRCan). For a full listing refer to *International Real-Time Magnetic Observatory Network* [7].



Additional data could be found at research institutions and academic universities or other entities with installed magnetometers.

The *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012 [8] provides equipment specifications and data format protocols.

[3] As of November 2019, a draft copy can be found at: https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_Data_Reporting_Instruction_draft.docx

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Violation Risk Factor and Violation Severity Level Justification

Project 2019-01 Modifications to TPL-007-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification for TPL-007-4, Requirement R1
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R1
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R2
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R2
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R3
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R3
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R4
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R4
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R5
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R5
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R6
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R6
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R7
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R7
The VSL did not substantively change from the TPL-007-3 Reliability Standard or FERC-approved TPL-007-2 Reliability Standard. In the Severe VSL, the word "have" was replaced with "develop" to more closely reflect the language of the Requirement.

VRF Justification for TPL-007-4, Requirement R8
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R8
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R9
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R9
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R10
The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R10
The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VSL Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VRF did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VSL did not change from the TPL-007-3 Reliability Standard or the FERC-approved TPL-007-2 Reliability Standard.

VSLs for TPL-007-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications for TPL-007-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs retain the VSLs from the TPL-007-3 Reliability Standard, approved by FERC in TPL-007-2, with the exception of removing one part of the lower VSL to reflect the removal of subpart 8.3 in proposed TPL-007-4. As a result, the proposed VSLs do not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VSLs for TPL-007-4, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance. Further, the VSLs are consistent with those assigned for Requirement R7, pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is being proposed for this requirement.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The proposed VRF is consistent among other FERC approved VRFs within the standard, specifically Requirement R7 pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a supplemental GMD Vulnerability Assessment could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Consideration of Issues and Directives

Project 2019-01 Modifications to TPL-007-3

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Modify the provision in Reliability Standard TPL-007-2, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]", by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis. Under this option, responsible entities seeking an extension would submit the information required by Requirement R7.4 to NERC and the Regional Entities for their consideration of the request.	FERC Order No. 851, P 5 and P 50	The SDT proposed the modified language in Requirement R7.3 and R7.4 to require time extensions for completing CAPs be submitted to the ERO for approval. The proposed modified language reads as follows: 7.3. Include a timetable, subject ~~to revision by the responsible entity~~ approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall: 7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and 7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP. 7.4. Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time ~~revised~~ if ~~situations beyond the control of the~~ responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~ provided in Part

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		7.3. The submitted ~~revised~~ CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~: 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity; ~~7.4.2 Description of the original CAP, and any previous changes to the CAP, with the associated timetables(s) for implementing the selected actions in Part 7.1; and~~ ~~7.4.3~~7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable;~~,~~ and ~~the updated timetable for implementing the selected actions.~~ ~~7.4.4~~7.4.3 Updated timetable for implementing the selected actions in Part 7.1.
Submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.	FERC Order No. 851, P 4 and P 39	The SDT drafted TPL-007-4 Requirement R11 to address require CAPs for supplemental GMD vulnerabilities and to require extensions to these plans to be approved by NERC and the Regional Entities, as appropriate, ~~in~~ where situations beyond the control of the responsible entity prevent implementation of the CAP in the two and four year timelines provided in the standard for non-hardware and hardware

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	Source	Consideration of Issue or Directive
		mitigation, respectively. This language is the same as the modified Requirement R7 which addresses CAPs for the benchmark GMD vulnerability assessment. Requirement R8 was also modified to remove the original R8.3 which stated "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."

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DRAFT TPL-007-4 CAP Extension Request Review Process

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Table of Contents

Introduction

Background

This Electric Reliability Organization (ERO) Enterprise[1] TPL-007-4 Corrective Action Plan (CAP) Extension Review Process document addresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to CAPs developed under TPL-007-4 to ensure a timely, structured and consistent approach to CAP extension request submittals and processing.

NERC Compliance Assurance will maintain this document under existing ERO Enterprise processes. This document will be reviewed and updated by NERC Compliance Assurance, as needed.

[1] The ERO Enterprise is comprised of NERC and the Regional Entities.

Process Overview

If a registered entity (entity) has determined that a Corrective Action Plan (CAP) developed in accordance with TPL-007-4 Requirements R7 or R11 cannot meet the timetable provided per R7 Part 7.3 or R11 Part 11.3 due to situations beyond the control of the responsible entity, then the entity will submit an extension request to the ERO Enterprise for approval prior to the original required CAP completion date.

The steps outlined here should be followed to ensure a timely, structured and consistent approach to extension request submittals and processing.

The entity will work with the Regional Entity designated as its CEA as outlined in this process. The entity submitting the extension request will be referred to as the 'submitting entity' and may represent only itself or multiple registered entities who have developed a joint extension request. The submitting entity is responsible for ensuring all registered entities who are jointly submitting the extension request are listed in the requested information below and for distributing any communications from its CEA to the other entities that are part of the joint extension request. If a joint extension request is submitted for multiple registered entities who have different Regional Entities designated as the CEA, the submitting entity's CEA will perform the steps outlined in this process and will be responsible for coordinating with the Regional Entity(ies) that are the designated CEA for the additional entities party to the joint extension request.

For entities in Coordinated Oversight, the CEA for this process is the Lead Regional Entity (LRE). The LRE will coordinate with the Affected Regional Entity(ies) (ARE) and the AREs may participate in the joint review as well.

Step 1 – Registered Entity Submittal

If an entity determines that it cannot meet the required timetable for completing a CAP, the submitting entity will contact their CEA to coordinate submittal of an extension request. The submitting entity will submit the request to their CEA using the template provided in **Appendix A: Entity Submittal Template**.

Entities are encouraged to submit the extension request as soon as they are aware they will not meet the CAP completion date but no later than 60 days before the original required completion date to allow the CEA and NERC time to approve the extension request before the original required completion date.

If CAP extension requests are submitted less than 60 calendar days before the original required completion date, the CEA and NERC may not have sufficient time to review the extension request before the required completion date. This could cause the entity not to meet its obligations under TPL-007-4 R7 Part 7.3 and R11 Part 11.3. It is the submitting entity's responsibility to ensure that all information detailed in TPL-007-4 Part 7.4 or 11.4 and requested in the Entity Submittal Template is provided in the entity's extension request submittal to facilitate the CEA and NERC review.

Step 2 – ERO Enterprise Review

The CEA will acknowledge receipt of the submission in writing within 15 calendar days and review that all information detailed in TPL-007-4 R7 Part 7.4 or R11 Part 11.4 and requested in the Entity Submittal Template is provided in the submitting entity's extension request submittal. The CEA will work with the submitting entity to provide any missing information and will notify NERC of the extension request submittal when acknowledging receipt of the submission.

CMEP staff from the CEA and NERC will then perform a joint review of (1) the situation(s) beyond the control of the entity preventing implementation of the CAP within the identified timetable; and (2) the revisions to the CAP and updated timetable for implementing the selected actions. Any additional information requested to support the extension request review will be coordinated with the submitting entity by the CEA. The CEA and NERC will complete the review within 45 calendar days or provide notification to the submitting entity that it extending the time needed for review.

The Standard language states that an entity will submit an extension request for a full or partial delay in the implementation of the CAP within the timetable provided in TPL-007-4 R7 Part 7.3 or R11 Part 11.3. The determination whether to approve the extension request will be based on the specific facts and circumstances provided as to how the situations causing the delay in completing the CAP are beyond the control of the entity.

Examples of situations beyond the control of the responsible entity include, but are not limited to:
- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Due diligence to order equipment, plan Right-of-Ways, obtain permits, etc., will be considered as part of the determination of whether a particular set of facts and circumstances constitute situations beyond the control of the entity. Additionally, cost may be a factor in whether a particular set of facts and circumstances constitute situations that are beyond the control of the entity. However, the cost of mitigation alone is not likely to be determined to be a situation that is beyond the control of the entity.

Step 3 – Registered Entity Notification

The CEA will communicate the approval or denial of the extension request or continuation of the time needed to review the extension request in writing to the submitting entity including the rationale for the determination. For any continuation of the review, the CEA will also provide the submitting entity a revised timeline for when the determination will be provided.

Appendix A: Entity Submittal Template

[Will be formatted into a form for submission that includes the following information]

Submitting entity name:

Submitting entity NCR#:

Submitting entity contact name and information:

Coordinated Oversight Group # (if applicable):

Regional Entities impacted (for MRREs only):

Is this extension request being submitted jointly with another entity? If yes, please provide:

1. NCR#'s for addition entity(ies)
2. Regional Entity that is the CEA for additional entity(ies)

Start date of CAP:

Original completion date of CAP:

Description of system deficiencies identified and selected actions to achieve required System performance per TPL-007-4 Part 7.1:

Circumstances causing the delay for fully or partially implementing the selected actions:

Explanation for why circumstances causing the delay are beyond the entity's control:

Description of revisions to the selected actions, if applicable:

New proposed completion date of CAP:

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Background

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The steps outlined here should be followed to ensure a timely, structured and consistent approach to extension request submittals and processing.

The entity will work with the Regional Entity designated as its CEA as outlined in this process. The entity submitting the extension request will be referred to as the 'submitting entity' and may represent only itself or multiple registered entities who have developed a joint extension request. The submitting entity is responsible for ensuring all registered entities who are jointly submitting the extension request are listed in the requested information below and for distributing any communications from its CEA to the other entities that are part of the joint extension request. If a joint extension request is submitted for multiple registered entities who have different Regional Entities designated as the CEA, the submitting entity's CEA will perform the steps outlined in this process and will be responsible for coordinating with the Regional Entity(ies) that are the designated CEA for the additional entities party to the joint extension request.

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Entities are encouraged to submit the extension request as soon as they are aware they will not meet the CAP completion date but no later than 60 days before the original required completion date to allow the ~~ERO Enterprise~~CEA and NERC time to approve the extension request before the original required completion date.

~~All CAP extension requests must be approved by the ERO Enterprise prior to original required CAP completion date.~~If CAP extension requests are submitted less than 60 days before the original required completion date, the CEA and NERC may not have sufficient time to review the extension request before the required completion date. This could cause the entity not to meet its obligations under TPL-007-4 R7 Part 7.3 and R11 Part 11.3. It is the submitting entity's responsibility to ensure that all information detailed in TPL-007-4 Part 7.4 or 11.4 and requested in the Entity Submittal Template is provided in the entity's extension request submittal to facilitate the CEA and NERC review.

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The Standard language states that an entity will submit an extension request for a full or partial delay in the implementation of the CAP within the timetable provided in TPL-007-4 R7 Part 7.3 or R11 Part 11.3. ~~The CEA and NERC will~~The determin~~e~~ation whether to approve the extension request will be based on the specific facts and circumstances provided as to how the situations causing the delay in completing the CAP are beyond the control of the entity.

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Submitting ~~Entity~~ entity name:

Submitting entity NCR#:

~~Primary~~ Submitting entity contact name and information:

Coordinated Oversight Group # (if applicable):

Regional Entities impacted (for MRREs only):

Is this extension request being submitted jointly with another entity? If yes, please provide:

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2. ~~1.~~ Regional Entity that is the CEA for additional entity(ies)

Start date of CAP:

Original completion date of CAP:

Description of system deficiencies identified and selected actions to achieve required System performance per TPL-007-4 Part 7.1:

Circumstances causing the delay for fully or partially implementing the selected actions:

Explanation for why circumstances causing the delay are beyond the entity's control:

Description of revisions to the selected actions, if applicable:

New proposed completion date of CAP:

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Standards Announcement

Project 2019-01 Modifications to TPL-007-3

Final Ballot Open through November 22, 2019

Now Available

A 10-day final ballot for **TPL-007-4 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern, Friday, November 22, 2019.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience issues navigating the SBS, contact Linda Jenkins.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668.

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BALLOT RESULTS

Ballot Name: 2019-01 Modifications to TPL-007-3 TPL-007-4 FN 2 ST
Voting Start Date: 11/13/2019 8:17:24 AM
Voting End Date: 11/22/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 276
Total Ballot Pool: 292
Quorum: 94.52
Quorum Established Date: 11/13/2019 10:08:13 AM
Weighted Segment Value: 78.95

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	50	0.758	16	0.242	0	9	7
Segment: 2	6	0.5	5	0.5	0	0	0	1	0
Segment: 3	67	1	42	0.764	13	0.236	0	9	3
Segment: 4	13	1	10	0.833	2	0.167	0	1	0
Segment: 5	65	1	36	0.706	15	0.294	0	9	5
Segment: 6	49	1	27	0.614	17	0.386	0	4	1
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	292	6.3	178	4.974	63	1.326	0	35	16

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	Ben Engelby		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Abstain	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	N/A
1	Dairyland Power Cooperative	Renee Leidel		Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Ayman Samaan		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Trey Melcher		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Negative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	N/A
1	Western Area Power Administration	sean erickson		Negative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Kent Feliks		Negative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		None	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	N/A
3	Xcel Energy, Inc.	Joel Limoges		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Negative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
5	Entergy	Jamie Prater		Negative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Negative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	WEC Energy Group, Inc.	Janet OBrien		Negative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	N/A
6	Entergy	Julie Hall		Negative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Negative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	N/A
6	Western Area Power Administration	Rosemary Jones		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Exhibit G

Standard Drafting Team Roster for Project 2019-01

Standard Drafting Team Roster

Project 2019-01 Modifications to TPL-007-3

	Name	Entity
Chair	Emanuel Bernabeu	PJM Interconnection
Vice Chair	Per-Anders Lof	National Grid
Members	Mike Steckelberg	Great River Energy
	Rui Sun	Dominion Energy
	Jow Ortiz	Florida Power & Light (NextEra Energy)
	Cynthia Yiu	Hydro One Networks Inc.
	Reynaldo Ramos	Southern Company Services
	Aster Amahatsion	American Electric Power
	Justin Michlig	MISO
PMOS Liaison(s)	Michael Brytowski	Great River Energy
	Sean Cavote	PSEG Services Company
NERC Staff	Alison Oswald – Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti – Senior Counsel	North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit H

Consideration of Directives

Consideration of Issues and Directives

Project 2019-01 Modifications to TPL-007-3

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Modify the provision in Reliability Standard TPL-007-2, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]", by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis. Under this option, responsible entities seeking an extension would submit the information required by Requirement R7.4 to NERC and the Regional Entities for their consideration of the request.	FERC Order No. 851, P 5 and P 50	The SDT proposed the modified language in Requirement R7.3 and R7.4 to require time extensions for completing CAPs be submitted to the ERO for approval. The proposed modified language reads as follows: 7.3. Include a timetable, subject ~~to revision by the responsible entity~~ approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall: 7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and 7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP. 7.4. Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time ~~revised~~ if ~~situations beyond the control of the~~ responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~ provided in Part

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		7.3. The submitted ~~revised~~ CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~: 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity; ~~7.4.2 Description of the original CAP, and any previous changes to the CAP, with the associated timetables(s) for implementing the selected actions in Part 7.1; and~~ ~~7.4.3~~7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable;~~,~~ and ~~the updated timetable for implementing the selected actions.~~ ~~7.4.4~~7.4.3 Updated timetable for implementing the selected actions in Part 7.1.
Submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.	FERC Order No. 851, P 4 and P 39	The SDT drafted TPL-007-4 Requirement R11 to address require CAPs for supplemental GMD vulnerabilities and to require extensions to these plans to be approved by NERC and the Regional Entities, as appropriate, ~~in~~ where situations beyond the control of the responsible entity prevent implementation of the CAP in the two and four year timelines provided in the standard for non-hardware and hardware

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		mitigation, respectively. This language is the same as the modified Requirement R7 which addresses CAPs for the benchmark GMD vulnerability assessment. Requirement R8 was also modified to remove the original R8.3 which stated “an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.”